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Ukraine: Challenges Facing the Gas Sector

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This report was based on information from a variety of sources. Wherever possible, information from official Ukrainian sources (primarily Naftogaz and NERC) has been used. When information is not available from these sources, other sources of data have been used which has created the possibility for some minor conflicts in the information presented. Other sources of information include both publicly available information and information available to the World Bank as a result of studies commissioned by the Bank or otherwise provided to the Bank. These other sources include: the Energy Charter Secretariat; the BDO audits of Naftogaz companies; the IMF; the BP Statistical Review of World Energy 2003; Gas Strategies, EconoMatters Ltd.; Professor Paul Stevens, University of Dundee; Cambridge Energy Research Associates; Economic Consulting Associates; and Hunton and Williams.

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Abbreviations and Acronyms

BCM	Billion Cubic Meters
CHP	Combined Heat and Power Plant
$	Refers throughout to US Dollars
EU	European Union
FDI	Foreign Direct Investment
FSU	Former Soviet Union
GATT	General Agreement on Trade and Tariffs
GDP	Gross Domestic Product
IMF	International Monetary Fund
JSC	Joint Stock Company
Km.	Kilometers
LNG	Liquefied Natural Gas
MCM	Thousand Cubic Meters
mm	Million
NERC	National Electricity Regulatory Commission
PSA	Production Sharing Agreement
T&D	Transmission and Distribution
TCM	Trillion Cubic Meters
TOE	Tons of Oil Equivalent
UAH	Ukrainian Hrivnies
UGSS	Unified Gas Supply System
VAT	Value Added Tax
WTO	World Trade Organization

Executive Summary

Overview

1. Ukraine enjoys outstanding natural endowments and a key strategic location on the East-West gas transportation corridor. Despite this, Ukraine is not taking full advantage of the opportunity to exploit these assets in order to maximize their contribution to the economic development of the country. In order to optimize the use of these assets, Ukraine will need to overcome a number of challenges. The purpose of this report is to provide a consistent basis for future discussion between the Government of Ukraine and the World Bank on approaches to reforming the gas sector.

2. In order to understand the challenges facing the gas sector in Ukraine, it is instructive to look at an analysis of the strengths, weaknesses, opportunities and threats for the sector. This analysis is shown in Box 1. Ukraine should seek to exploit the opportunities for the sector while neutralizing the threats. To do so it needs to take full advantage of the sector's strengths while addressing the weaknesses.

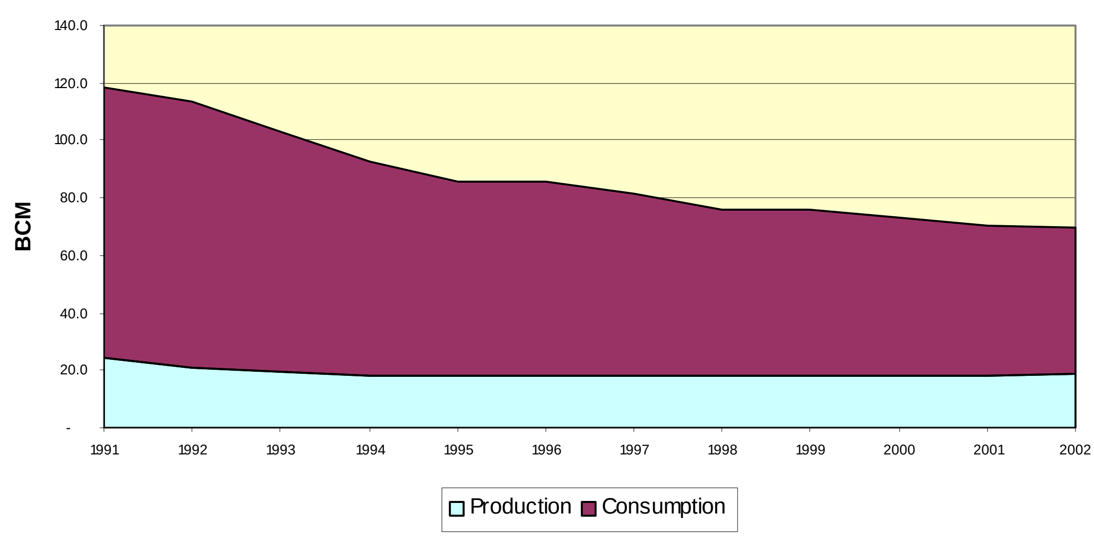
Box 1
Summary Analysis of the Gas Sector in Ukraine

Strengths	Weaknesses
- Domestic gas reserves (1.12 TCM) and production (18.8 BCM in 2002) - Well developed transmission system - Large gas storage facilities - Extensive distribution system	- Lack of competition - Deteriorating transmission and distribution facilities - Tariffs below the economic value of the gas - Limited regulatory capacity - Debt overhang - Magnet for corruption
Opportunities	**Threats**
- To secure significant additional transit revenue - To effect a substantial increase in production leading to reduced reliance on imports - To attract private investors, eliminating government obligations and securing needed financing - To eliminate the implicit subsidies in the sector - To take advantage of environmental improvements (e.g. carbon trading) - To effect energy efficiency improvements	- Reduction in gas transit - Severe deterioration/potential collapse of portions of the gas infrastructure - Increases in implicit subsidies in the sector - Increase in the debt overhang - Increasing role of non-desirable business interests - Monopoly abuses

3. In the mid 1990s the Government was faced with three major challenges in the gas sector: (i) stemming the decline in domestic production which had dropped by 25% between 1991 and 1994 - (Figure 1 below shows production and consumption levels from 1991 through 2002); (ii) ensuring that only those that paid for imported gas received it; and (iii) preserving Ukraine's strategic position on the East-West gas transport corridor. As a result, the Government embarked on a reform program.

Figure 1

Natural Gas Production and Consumption



Source: Naftogaz

4. In 1995, the State Geology Committee started awarding exploration and later production licenses to private (mostly foreign) companies. In 1996, sovereign guarantees for gas imports were eliminated and private gas traders were given exclusive rights to import and sell gas to all consumers in specific oblasts assigned to them. With this measure Ukraine became one of the first countries in the World where gas transmission and distribution were unbundled from gas import and supply.

5. These reforms had mixed results. On the positive side, foreign direct investment started to flow to the upstream gas industry. Traders managed to improve payment discipline among industrial customers and the Government stopped accumulating additional debt to Russia and Turkmenistan for gas imports[1]. On the negative side, none of the main multinational oil and gas companies found the legal and regulatory framework attractive enough to make large scale investments given the perceived limitations of the underlying geology. The frequent redistribution of supply franchises among traders led to occasional violence and accusations of corruption, and payment discipline remained low among households, district heating companies and power plants.

[1] Debts, however, subsequently built up again creating tensions between Ukraine and Russia. These were eventually resolved through an agreement that was signed between Russia and Ukraine in October 2001 to restructure Ukraine's outstanding gas debts to Russia (these were agreed at a level of $1.4 billion).

6. Concerns began to emerge about maintaining the reliability of the transmission system and about deficiencies in the tracking and control of gas flows in the transmission and distribution network. This led to a debate on the requirement for further reforms with arguments being made for both increased State control and for reduced State intervention through the separation and privatization of production, transmission and marketing activities, elimination of exclusive gas franchises, privatization of gas distribution companies, liberalization of gas prices and establishment of an independent regulatory body.

7. Key results of this debate were (i) the elimination of exclusive supply franchises and the issue of permits to traders who have the right to import and sell gas; (ii) a decision in February 1998 to establish Naftogaz as a vertically integrated company whose assets would include everything that the State owned in the oil and gas industry; and (iii) a Presidential decree ordering the transfer of responsibility for regulation of the gas industry from the Ministry of Economy and the State Oil and Gas Committee to the National Electricity Regulatory Commission.

8. Since 1998, Naftogaz has steadily consolidated its hold on the gas sector. It produces over 95% of domestic gas, controls and operates the transmission network and now handles essentially all the imported gas. (Over the past year the role of the independent gas trader has effectively been eliminated). From a supply standpoint, Ukraine is now operating under the "single buyer" model with Naftogaz playing the role of the single buyer.

9. The main improvement in the sector over the last several years has been the significant increase in cash collections[2]. Naftogaz and the Government report that cash collections are now at a level of about 89%. Despite this, the sector remains financially weak and debts from consumers are continuing to accumulate. Tariffs are below import parity levels and, when compared with this economic benchmark, implicit subsidies are being generated on the order of $1 billion per year[3]. Tax arrears on the part of Naftogaz have been steadily increasing and Naftogaz is the largest tax debtor in the country with tax debts in excess of UAH 4.6 billion ($0.85 billion equivalent) at the end of 2002.

10. The challenges now facing the sector are similar to those identified in the mid 1990s. In brief, the key challenges are as follows:

i. To establish and maintain financial viability within the gas sector;
ii. To secure funding for the capital investments required to ensure optimum exploitation of Ukraine's gas sector assets; and

[2] The improvement in cash collections owes a great deal to strong support provided by the Government to this effort, including the personal commitment of the then Deputy Prime Minister responsible for energy to secure improvements in this area.
[3] The World Bank estimates that the implicit subsidies in the sector amounted to $1.10 billion in 2001 and $1.06 billion in 2002, assuming an import parity price of $50 per thousand cubic meters of gas.

iii. To maximize the economic rent to the State associated with gas transit through Ukraine.

11. In May 2004, Ukraine will become an immediate neighbor of the European Union (EU). The country, therefore, is also faced with the need to harmonize its energy markets with the internal EU market if it is to take full advantage of the trading opportunities associated with being an immediate neighbor. This, in turn, will pave the way for the creation of a more competitive domestic gas market. At the same time there is a real possibility that supply availability of gas for import will tighten. While this may be accompanied by some increase in the number of potential suppliers it raises the possibility that Ukraine will be faced with having to pay higher prices for its imports. This underscores the importance of establishing a competitive environment since this should serve to mitigate some of the impact of higher import prices in terms of the prices charged to the ultimate consumer.

Addressing These Challenges

12. The key conclusions and recommendations of the report are summarized as follows:

Challenge Number 1:

To establish and maintain financial viability within the gas sector.

13. The gas sector plays a major role in the economy of Ukraine. Gas represents about 50% of Ukraine's primary fuel consumption, domestic gas production meets about 12% of the country's primary fuel needs and the transit gas pipeline system is a significant strategic asset generating annual revenues of about $1.5 billion. The sector, however, provides implicit subsidies to the economy on the order of $1 billion per year (equivalent to about 2.5% of GDP) and does so at the cost of being unable to generate the funds needed for prudent reinvestment in the sector both to maintain existing assets and to expand operations with the objective of more effectively exploiting Ukraine's underlying hydrocarbon resource base and strategic location. These subsidies are effectively provided by Naftogaz and its subsidiary companies.

14. In providing these subsidies, Naftogaz and its subsidiaries have been forced to forego potential profits associated with domestic gas production and attributable to payments received in kind for the transit of Russian gas. Naftogaz has also proved unable to meet its full tax obligations with the result that it is now the largest tax debtor in the country with tax debts in excess of UAH 4.6 billion (equivalent to $0.85 billion).

15. While collection problems, which have been substantially reduced over the last few years, contribute to the creation of these implicit subsidies, by far the largest component of the subsidies results from gas being priced at below its true economic value. At present, the economic value of all the gas consumed in Ukraine is equivalent to import parity cost which is approximately $50 per thousand cubic meters (MCM).

16. Continuing efforts to improve collections and a focus on reducing operating costs and commercial losses are needed and will contribute to an improvement in the financial outlook for the gas sector. However, until gas price tariffs are brought up to levels that cover the full economic cost of the gas, the sector will remain financially susceptible and the country's ability to achieve optimum exploitation of its gas resources and infrastructure will be constrained. Consequently, a priority recommendation is that Ukraine develop and implement a medium term tariff policy designed to bring gas tariffs up to full economic recovery levels over a period of time. Ukraine should also introduce quality standards and an approach for monitoring these standards. This would allay the concern that higher prices could be introduced in an environment of declining quality standards.

17. In May 1995, the Housing and Municipal Service Allowance program was launched. The original objective of this program was to shield families from the impact of rapidly rising fuel costs. While this program benefits from an effective administrative structure there are concerns about the effectiveness of its targeting – it suffers from problems of both inclusion and exclusion[4]. Consequently the timing of the implementation of tariff increases needs to take into account the timing of reforms to the social safety net. Provided this housing subsidy program is adequately funded and adequately targeted, affordability of gas priced at full economic recovery levels should not be a major issue. It is, however, essential that such funding be provided. A higher level of tariffs will, among other things, increase Naftogaz' tax payments and allow it to address its tax arrears and these represent sources to meet these additional funding needs.

18. Naftogaz and its subsidiary companies will be major beneficiaries of increases on domestic tariff levels. The State needs to be satisfied that the resultant additional revenues will be managed appropriately. The government may, therefore, want to consider linking action on domestic tariff levels to actions to increase the accountability and transparency of Naftogaz operations (see further discussion below).

Challenge Number 2:

To secure funding for the capital investments required to ensure optimum exploitation of Ukraine's gas sector assets.

19. Ukraine is endowed with substantial gas reserves and has the potential to increase production significantly. Naftogaz own assessment suggest that gas production could be increased by as much as 10 to 12 BCM per year. Some industry assessments have suggested a greater increase might be possible. The country, however, will be pressed to generate the investment funds from internal sources to effect a production increase of this magnitude which could require investments on the order of $1.5 to $2 billion. In addition, Ukraine has sizeable funding needs to maintain its existing infrastructure and would also require substantial capital if it is to expand the gas transit line to take

[4] See the World Bank report "Ukraine Improving Safety Nets and Labor Market Policies to Reduce Poverty and Vulnerability", August 2003.

advantage of a potential future increase in Russian gas exports to Europe. Consequently, if Ukraine is to maximize the value from its gas resource base and its gas infrastructure, it will need access to external capital in the form of investments and/or loans.

20. The level of foreign direct investment inflows into a country is a key indicator as to how attractive an investment climate exists within the country. Given the size of the Ukrainian economy, the level of foreign direct investment is very low. This indicates a need to introduce reforms to make the investment climate more attractive if external capital is to be attracted to the gas sector.

21. In establishing an acceptable investment climate for the gas sector perhaps the most critical issue is to ensure that Naftogaz, with its monopoly position in the sector, does not act as an impediment to investment. What is needed is a significant increase in favorable perceptions concerning the transparency of Naftogaz operations.

22. From a structural standpoint, an unbundling of gas operations both vertically (i.e. by separating production, transmission, storage and distribution) and horizontally (i.e. by setting up a series of competing production companies) would be desirable since this would eliminate any potential conflict of interest and would promote gas to gas competition. This does not require a break-up of Naftogaz, which may not be an acceptable option at this time. Rather, it could be handled in a virtual fashion by ensuring full separation of subsidiary units into discrete operating companies with financial and managerial autonomy, with each company being expected to function as an independent commercial enterprise, but with an obligation to report financial and operating results to the holding company.

23. Naftogaz should also embrace best practice transparency requirements for national oil companies both at the holding company and at the subsidiary level. (Best practice in this regard is epitomized by companies such as Statoil of Norway and PetroCanada both of whom comply with the reporting and disclosure requirements applicable to publicly quoted private sector enterprises). As a first step, this should involve a program to place the entire company on international accounting standards. This will be an essential requirement if Naftogaz is to have ongoing access to commercial borrowing on reasonable terms, financed off its balance sheet.

24. In considering the future structure of the gas sector, Ukraine should take particular note of the provisions of the applicable European Union (EU) directives. Directives 98/30/EC and 03/55/EC provide common rules on storage, transmission, supply and distribution of natural gas and include provisions which stipulate specific structural requirements for the gas industry in each of the member countries. In May 2004, Ukraine will become an immediate neighbor of the EU. If Ukraine is to take maximum advantage of the opportunity for future trade with the EU that its location provides, it should plan to harmonize its own energy market structure with the structure of the internal EU market.

25. The willingness of both the government and Naftogaz to make attractive opportunities (whether upstream or downstream) available to potential investors will also have a direct bearing on the level of potential investor interest in the sector.

26. A further factor that will significantly affect investor and lender perceptions is the level of consumer price tariffs in the domestic market. Bringing all tariffs up to full economic value levels will greatly enhance the perceived attractiveness of the market, as will the achievement of full payment compliance in the sector.

Challenge Number 3:

To maximize the economic rent to the State associated with gas transit through Ukraine.

27. Ukraine's high pressure gas transit line is a major strategic asset. However, if Ukraine is to extract the maximum benefit from this asset it needs to convince Russia that it will behave as a "good transit country" for the indefinite future and that it should be the preferred route for future increases in Russian gas deliveries to Europe. At the same time, Ukraine needs to ensure that the State receives a fair share of the economic rent associated with gas transport. It should also provide support to the development of the domestic gas production sector by ensuring that some transmission capacity is available for exports of Ukrainian gas.

28. Discussions have been underway about establishing a consortium involving Ukraine, Russia (in the form of Gazprom) and, possibly, one or more European partners to manage the operation of the transit pipeline system. Discussions have addressed both the existing transit system and a possible new transit pipeline. Such an arrangement, particularly for the existing transit system, should go a long way to achieving the goal of convincing Russia that Ukraine will act as a "good transit country" in the future. If structured as a concession or outright privatization, it should also address the question of funding sources for needed capital investments in the system. The Bank supports Ukraine's efforts to establish such a consortium to manage the operation of the existing system. The Bank would also support a consortium approach to construction of a new pipeline, but believes that putting in place a satisfactory arrangement to manage the existing system should be accorded priority. We believe that a concession arrangement is likely to offer the best prospects for reaching a satisfactory agreement for the existing transit system.

29. The transit tariff is currently paid largely in kind, in the form of gas. In 2002, the tariff consisted of a cash payment of about $141 million and a payment in the form of gas of about 26 billion cubic meters (BCM). This represented a total value of almost $1.5 billion. The transit arrangements also call for a tax payment by Naftogaz of $0.29/MCM per 100 kilometers of gas transited through the system. In 2002, this tax payment amounted to about $380 million which represented the total of direct contributions to the State associated with the transit. This level of contributions to the State budget, however, is low when compared with other gas transit arrangements.

30. With or without a new arrangement for the management and operation of the transit pipeline system, the transit tariff needs to be reviewed and the amount allocated to the State budget needs to be re-examined. Ukraine should also seek to have the payment of tariffs converted from a predominantly in kind arrangement to a 100% cash arrangement. Information on the arrangements should be made publicly available.

Summary Conclusion

31. The key conclusion that can be drawn from this assessment of the gas sector is that reform measures will be critical to the long term health of the economy overall. The cost of continuing business as usual will translate into a lack of investment, a loss of potential future transit revenues, a poor quality of service, reduced energy security, increased risk of system deterioration and ultimately collapse and a significant impediment to future trade relations with the EU. The implicit subsidies alone represent a drain on the economy equivalent to 2.5% of annual GDP and the failure to create an attractive climate for investment in the gas sector will impact other sectors and will likely perpetuate Ukraine's poor overall performance in attracting foreign direct investment. There will clearly be costs associated with reforming the system, these will include addressing the social consequences, dealing with special interest groups and overcoming political resistance. The benefits, however, will significantly outweigh the costs.

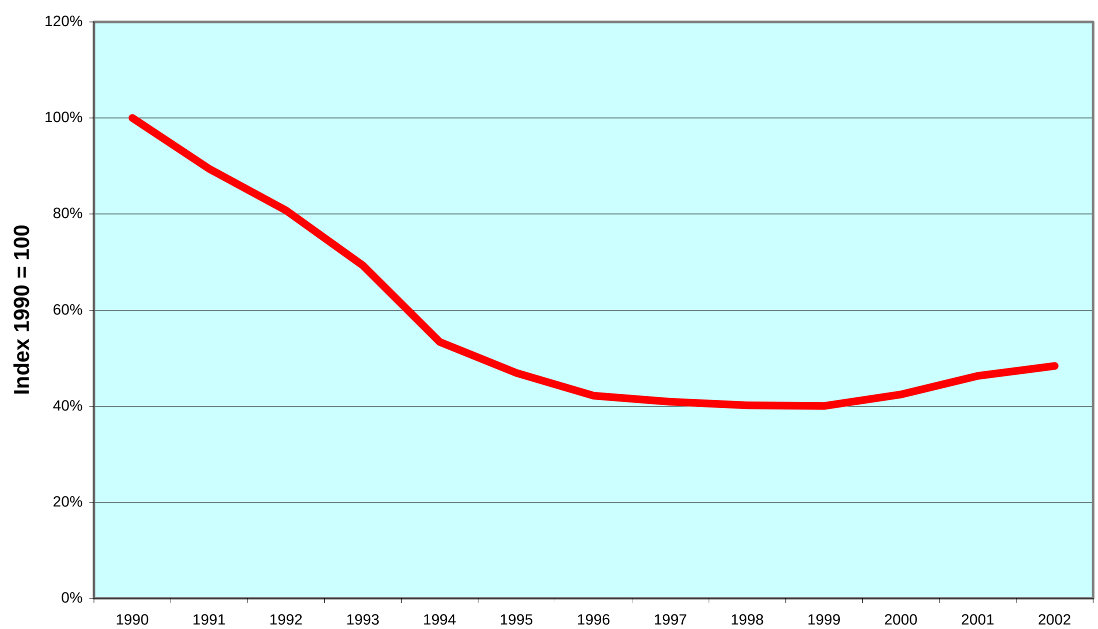
Establishing and Maintaining Financial Viability Within the Gas Sector

The Transition Process

32. Ukraine is now more than ten years into a transition process that commenced immediately after Ukraine became independent. As elsewhere in the former Soviet Union (FSU), the process in Ukraine can be characterized as reflecting three transitions rolled into one:

i. A **political transition –** from a highly controlled centralized political system to a more decentralized and democratic form of government;
ii. An **institutional transition –** from the institutional framework of central planning towards the institutions of a market economy; and:
iii. An **economic transition –** involving the disintegration of the highly integrated economic space of the FSU, with the resultant disruptions in trade, financial and labor market connections.

Figure 2
Changes in Real Output – Ukraine - 1990 - 2002



33. For each of these areas there have been broadly two stages of transition in the FSU countries:

i. A first stage of economic decline, involving the disintegration and destruction of existing political, institutional and economic relations;
ii. Followed by a second stage of recovery, involving rebuilding, reform and integration with the world economy.

34. As shown in Figure 2 above, Ukraine initially experienced seven years of dramatic economic decline starting in 1990, losing 59% of its measured GDP. It then stagnated for another three years through 1999. Fortunately, in 2000, Ukraine started to benefit from the vigorous economic recovery that began for the region as a whole in 1999 and is set to continue in 2003 and beyond. However, GDP in 2002 was still about 51% below its 1990 level.

35. The energy sector has a critical role to play in the continuing transition process. The energy sector plays a significant role in the overall economy of Ukraine, as in other transition countries, and the World Bank's experience suggests that without energy sector reform and financial viability the transition process is much more difficult and delayed. Achieving sustained financial viability for the energy sector is, therefore, a critical objective. That is not to suggest that achieving sustained financial viability will, of itself, enable a country to complete the transition process successfully, but it does suggest that without addressing this component of the overall reform agenda, Ukraine will have difficulty completing its economic transition.

Subsidies in the Energy Sector

36. At the beginning of the transition period, energy supplies in Ukraine, as elsewhere in the FSU, were heavily subsidized and the three components that essentially make up the subsidies reflect the legacy of widespread expectations that energy should be provided at little or no cost. The three components are:

i. Non payments for energy consumed;
ii. Price structures that do not recover the full economic value of the energy supplied; and
iii. Excessive losses that reflect both operating inefficiencies and theft.

37. In seeking to reduce implicit energy sector subsidies, strengthening payments discipline is a critical first step. This means both securing a high level of payment compliance and replacing barter transactions with cash transactions. Achieving this involves an extensive effort focused at all categories of customer. Measures to address non payments among industrial, commercial and residential customers have to be coupled with the introduction of hard budget constraints. Without having in place effective measures to deal with non payments, efforts to increase tariffs to full cost recovery levels can be seriously undermined. Ukraine has recognized this and, as is indicated in Table 1, has taken significant measures in the last few years to address the issue.

Table 1
Naftogaz Gas Collections as a Percentage of Billings

	1999	2000	2001	2002
Total Collections	33.8 %	76.6 %	89.0 %	90.4 %
Cash Collections	15.8 %	49.2 %	87.0 %	88.9 %

Source: Naftogaz

38. In order for the energy sector in any particular country to be efficient and remain financially viable, tariff levels need to be high enough to recover costs. In the short run this means that tariffs have to cover input, operating and maintenance costs. Over the longer term, the tariffs also have to contribute the funds required for the capital investment needed to sustain the sector. Gas tariffs for 2001 and 2002 are shown in Table 2 below.

Table 2
Gas Tariffs

Category of Consumer	2001			2002		
	With VAT	Without VAT		With VAT	Without VAT	
	UAH 000s		$/MCM	UAH 000s		$/MCM
Households	120	100.0	18.62	120	100.0	18.76
Budget Enterprises	170	142.0	26.44	170	142.0	26.64
CHPs & Industrial Boilers	180	150.0	27.93	180	150.0	28.14
State Budget Communal	330	275.0	51.21	330	275.0	51.59
Industry:						
Chemical	327	272.5	50.74	325	270.8	50.81
Metallurgy	321	267.5	49.81	324	270.0	50.66
Machinery	345	287.5	53.54	333	277.5	52.06
Agriculture	332	276.7	51.52	335	279.2	52.38
Energy Complex	309	257.5	47.95	333	277.5	52.06
Other	330	275.0	51.21	327	272.5	51.13
Industry Average	330	275.0	51.21	330	275.0	51.13
Gencos (including CHPs)	330	275.0	51.21	330	275.0	51.13
Other Consumers	330	275.0	51.21	330	275.0	51.13
Average	252	210.0	39.11	252	210.0	39.40

Source: Naftogaz and World Bank analysis

39. As is indicated in Table 3 below, Ukraine imports over 70% of the gas it consumes. A portion of this gas (26 BCM in 2002) is provided, in kind, by Russia as payment for the transit of about 120 BCM of Russian gas to markets in Europe, Turkey and other CIS countries. The balance is purchased. At present, the primary supplier of these purchased volumes is Turkmenistan.

Table 3
Gas Supply and Demand in Ukraine (BCM)

	1997	1998	1999	2000	2001	2002
Domestic Production	18.1	18.0	18.1	18.1	18.4	18.8
Net Imports	63.1	57.6	57.6	55.3	52.1	51.0
Domestic Consumption	81.2	75.6	75.7	73.4	70.5	69.8
Imports as a % of Domestic Consumption	77.7 %	76.2 %	76.1 %	75.3 %	73.9 %	73.1%

Source: Naftogaz

40. Over 95% of Ukraine's domestic gas is produced by Naftogaz' affiliated companies, the balance being produced by a number of other enterprises. The breakdown of production among these various enterprises is shown in Table 4 below. Production costs will vary for each operation, but it is estimated that wellhead costs (i.e. excluding all transportation costs) are on the order of $17/MCM[5].

Table 4
Gas Production in Ukraine by Enterprise

Million Cubic Meters	2000	2001
NJSC Naftogaz Ukrainy		
- OJSC Ukranafta	3,306.1	3,292.5
- DK Ukrgazvydobuvann'a	13,421.7	13,585.4
- SJSC Chornomornaftogaz	764.4	786.4
Total	17,492.2	17,664.3
Other Enterprises		
- JV Poltava Gas and Oil Company	256.4	257.9
- JV UkrKarpatOil	5.6	5.8
- JV Delta	34.5	45.0
- JV Kashtan Petroleum	0.5	0.7
- CJSC Plast	68.4	68.9
- JV UkrNaftogaztechnologya	29.1	104.4
- JV Borislavs'ka Naftova Compania	0.0	27.9
- LLC Oberon-Voutill'a	16.7	10.3
- NJSC Ukraine Subsoil	147.9	163.4
Total Other Enterprises	559.1	684.3
Total Domestic Production	18,051.3	18,348.6

Source: Energy Charter Secretariat "Ukraine - Investment Climate and Market Structure in the Energy Sector"

41. The volumes of transit fee gas are based on negotiation between Ukraine and Russia. About 10% of the transit fee is paid in the form of cash with the balance being paid in the form of gas. This gas then has to be sold in the domestic market in order to generate the cash to cover the balance of the transmission costs, required tax payments and generate a profit for the gas transit activity. The costs of transmission and transit related tax payments therefore effectively define the "cost" of this transit fee gas. As is shown in Table 5, this "cost" was estimated to amount to the equivalent of $25.61/MCM of transit fee gas in 2002.

[5] The BDO audit of SC Gas of Ukraine for 2001 quotes the "cost of sales" for the companies own production (about 8 BCM) as UAH 119 or $22.16. NERC has indicated that transmission and distribution costs for domestic deliveries in 2001 averaged about UAH 10.66 for transmission and UAH 16.73 for distribution, resulting in a total transportation "cost" (tariffs were a little higher) equivalent to $5.10/MCM, resulting in a netback cost at the wellhead of about $17.06/MCM.

Table 5
Calculation of the Deemed Cost of Transit Fee Gas in 2002

Transit volume (BCM)	119.4
Cost of transit - UAH/MCM	18.68
Cost of transit - $/MCM	3.50
Cost of transit - $ million	418.5
Taxes attributable to transit volumes[6]	380.9
Cash transit fee payment	(141.3)
Net costs to be covered by transit fee gas	658.1
Volume of transit fee gas (BCM)	25.7
Deemed "cost" of transit fee gas $/MCM	25.61

Source: IMF data

42. The gas purchased from Turkmenistan reflects a combination of 50% cash and 50% barter relative to a price at the Turkmenistan border of $ 44/MCM. However, gas also has to be purchased from Turkmenistan to cover the transportation cost to bring gas from Turkmenistan to Ukraine. Consequently, Ukraine has entered into an arrangement to purchase 36 BCM of gas per year from Turkmenistan until 2006 and is negotiating arrangements for a 25 year purchase contract to start in 2007. 13.7 BCM of the purchase volume is provided as payment for transportation[7]. Arrangements for transportation have been made with EuralTransGas a trading company that also sells gas into European markets. EuralTransGas was established by Hungarian investors but, reportedly, Gazprom and Naftogaz each plan to buy half the company.

Table 6
Undiscounted Cost of Turkmenistan Imports

	$/MCM
Delivery price at Turkmen-Uzbek border	44.0
Kazakh transit	6.0
Russian transit	6.4
Delivered Cost	56.4

Source: United Financial Group Research

43. An analysis of purchase and transportation costs at full value suggests that the cost of gas from Turkmenistan delivered to the Ukraine border with Russia is $56.50/MCM (see Table 6 above). However, taking into account the discount effect of the barter arrangements, the estimated cost of gas imported into Ukraine is on the order of $50/MCM at the border with Russia. As a result, NERC uses a price of $50/MCM in valuing imported gas purchases. Within Ukraine, additional costs are incurred for transmission and distribution resulting in an average cost of delivery that is estimated to

[6] Calculated at a rate of $0.29/MCM/100 kilometers of transit volume.
[7] Source: United Financial Group.

have been about $ 55 to $56/MCM in both 2001 and 2002. However, as is indicated in Table 2, tariffs were below these levels for all categories of customers.

44. For the prices it regulates, NERC does follow a cost recovery methodology. However, NERC deems that all the gas supplied to households and to budget enterprises is sourced from domestic production. As the material balance shown in Table 7 below indicates, this is analytically feasible, although it does not take account of the fungibility of gas supplies. Consequently, in setting prices for households and budget funded enterprises, NERC sets prices that are linked to the cost of domestic production. This methodology does not take account of market or other economic values attributable to this gas. The effect of this is to force Naftogaz and its subsidiary companies to use the potential profits attributable to its domestic gas production to subsidize domestic consumers. Assuming a production cost of $17/MCM (as was noted above) and an alternative value of $50/MCM, Naftogaz is effectively being required to forego a potential before tax profit of some $33/MCM on its domestic production volumes. Not only that, but, as Table 7 indicates, Naftogaz has operational requirements for almost 9 BCM per year of gas and these are effectively deemed to be covered from other supplies (i.e. transit fee gas and/or purchased gas). This concept runs directly counter to normal international practice and is inconsistent with the EU Gas Directives.

Table 7
Ukraine's Gas Balance

	2001	2002
Supply:		
Domestic Production	18.4	18.5
Transit Fee Gas	22.0	25.7
Purchases to balance	30.1	25.6
Total	70.5	69.8
Operational Needs:		
Production	0.9	0.9
Transmission	7.0	7.1
Distribution	0.7	0.7
Total	8.6	8.7
Commercial Losses (at the distribution level)	1.9	1.6
Deliveries to Customers:		
Households	15.4	15.5
Budget Enterprises	0.9	0.9
Sub-Total	16.3	16.4
Heating Enterprises (including Kievenergo)	12.4	12.8
All Other	31.2	30.3
Total	59.9	59.5
Total Demand	70.5	69.8

Source: Naftogaz, NERC and World Bank analysis

45. While it would appear that Naftogaz should also have potential profits attributable to its transit gas, based on an assumed deemed "cost" of $25.61/MCM in 2002 (see Table

5 above), it seems that Naftogaz has also been forced to use some of these potential profits to subsidize domestic sales. The actual profits that finally resulted were evidently not sufficient to enable Naftogaz to cover all its financial obligations since the company was unable to meet its full tax obligations (as is shown in Table 8), with the result that Naftogaz is now the largest tax debtor in the country with tax debts in excess of UAH 4.6 billion ($0.85 billion equivalent) at the end of 2002 – this is equivalent to over 2% of 2002 GDP. In 2003, arrears are not accumulating, in part as a result of the profits associated with re-exports as well as increased sales into the domestic market following the demise of the independent traders.

Table 8
Naftogaz Tax Payments

	1999	2000	2001	2002
Tax Obligations (UAH billion)[8]	6.7	7.7	8.4	7.7
Payment Percentage	73 %*	65 %	73 %	77 %

* Includes substantial tax offsets in 1999
Source: IMF

46. As has been noted, the current pricing structure does not recognize the true economic value of domestic production. The minimum economic value for this production is import parity[9]. The combination of under recovery, through the tariff structure, of (i) the value of domestic gas production, (ii) the value of transit fee gas and (iii) the costs of imported gas, together with non payments have generated implicit subsidies on the order of $ 1 billion in each of the last two years. Table 9 below summarizes the subsidies attributable to under pricing of gas relative to a deemed economic value at the border with Russia of $50/MCM and taking account of collection levels. (The impact of excessive losses are not reflected in these calculations).

Table 9
Implicit Subsidies Provided by Naftogaz[10]

Year	Sales Million CM	Average Tariff $/MCM*	Billings $ million	Value $ Million	Collections $ Million	Subsidies $ Million
2001	42,148	$31.84	$1,341.8	$2,303.0	$1,206.3	$1,096.7
2002	42,273	$32.12	$1,357.7	$2,293.0	$1,230.9	$1,062.1

* Excludes VAT
Source: Naftogaz and World Bank analysis

47. These subsidies are not insignificant – in 2002 they were equivalent to 2.5 % of GDP. Of perhaps more concern, for the longer term, these implicit subsidies have prevented Naftogaz from generating the funds needed for prudent reinvestment in its operations both to maintain crucial strategic assets (such as the transmission pipeline) and to expand operations with the objective of more effectively exploiting Ukraine's

[8] These tax obligations include amounts attributable to Naftogaz crude oil production and refining operations as well as othe no gas related business activities.
[9] If unrestricted exports were possible at a higher price, export parity would become the appropriate comparative benchmark.
[10] Details of these calculations are provided in Attachment 1

underlying hydrocarbon resource base and strategic location. They have also prevented the State from generating an appropriate return on the strategic gas assets it owns.

48. While the significant increase in cash collections is one of the major achievements of the sector over the last several years, there is still opportunity for further improvement. As Table 9 shows, 100% collections in 2002 would have reduced the implicit subsidy by about $127 million.

49. Table 10 below indicates the comparative payment performance of the major categories of customer in 2001 and 2002. As this table indicates, the most significant continuing problem is attributable to the central heating plants and industrial boilers category. The poor payment performance of the heating enterprises is largely attributable to losses that result from an inadequate tariff structure for heat and hot water – this, in turn, reflects political decisions at the local level to hold down heat and hot water prices. The fact that these enterprises pay VAT on the basis of collections rather than on the basis of billings also contributes to the problem by reducing the incentive to press for full collections from their customers. The power generation companies (including JSC Kievenergo) also represent a fairly sizeable portion of the payment shortfall, although performance improved in 2002. The third problem category is the metallurgy industry.

Table 10
Payment Performance of Naftogaz' Customers

Category of Customer	2001				2002			
	Billings UAH mm	Payment %		Over/ (Under) UAH mm	Billings UAH mm	Payment %		Over/ (Under) UAH mm
		Total	Cash			Total	Cash	
Households	1,851.1	92.0	90.6	(148.1)	1,859.0	96.9	96.1	(57.6)
Budget Enterprises	154.9	89.1	72.6	(16.9)	156.7	96.0	93.9	(6.3)
CHPs & Boilers	1,666.4	84.0	81.7	(266.6)	1,695.8	78.4	75.9	(366.3)
State Budget Communal	44.2	107.7	102.1	3.4	37.0	103.0	97.2	1.1
Industry:								
Chemical	536.5	95.0	91.4	(26.8)	677.3	100.1	100.1	0.5
Metallurgy	858.3	91.7	88.4	(71.6)	1.347.3	91.4	87.5	(115.3)
Machinery	4.1	102.9	102.9	0.1	1.9	105.0	104.6	0.1
Agriculture	17.9	71.0	70.5	(5.2)	4.3	124.3	116.2	1.1
Energy Complex	1.9	104.6	13.9	0.1	0.1	69.9	25.4	(0.1)
Other	208.6	99.7	91.8	(0.7)	321.3	84.4	79.4	(50.2)
Industry Average	1,627.3	93.6	89.6	(104.1)	2,352.2	93.0	90.1	(163.9)
Gencos	1,480.3	76.6	73.4	(345.8)	1,351.7	93.0	93.0	(95.2)
JSC Kievenergo	605.5	92.2	90.7	(47.4)	691.8	82.3	82.3	(122.7)
Other Consumers	1,216.7	100.0	100.0	0.0	539.3	100.0	100.0	0.0
Total	8,646.4	89.4	87.1	(925.5)	8,683.5	90.4	88.9	(810.9)

Source: Naftogaz and World Bank analysis.

50. Non payments have resulted in a steady build up in payment arrears to Naftogaz. Table 11 summarizes the payment arrears overhang by customer category for the last three years.

Table 11
Payment Arrears to Naftogaz (Million UAH)

Category of Customer	Jan. 1, 2001	Jan. 1, 2002	Jan. 1, 2003
Households	998.0	996.3	1,055.6
Budget Enterprises	21.9	42.9	47.6
CHPs & Industrial Boilers	1,172.1	1,475.5	1,667.8
State Budget Communal	41.3	36.7	35.5
Industry:			
Metallurgy	0.0	71.7	141.8
All Other	148.3	152.3	173.3
Industry Total	148.3	224.0	315.1
Gencos	1,377.8	1,663.7	1,503.2
JSC Kievenergo	20.8	72.4	132.0
Other Consumers	0.0	0.0	0.0
Total	3,780.2	4,511.5	4,756.8

Source: Naftogaz

51. The accumulated payment arrears payable to Naftogaz of UAH 4.8 billion at the end of 2002 exceeded Naftogaz' accumulated tax debts. The payment arrears due Naftogaz need to be addressed along with the issue of Naftogaz tax arrears as part of a comprehensive restructuring of debt within the energy sector as a whole. At the same time, however, substantial efforts will be required to prevent these payment arrears from continuing to increase. It is encouraging that the arrears from the thermal generating plants showed a decline in 2002. However, the continuing accumulation of arrears by heating enterprises needs immediate attention. This may require some changes in management and associated accountability of these enterprises and may also require some government action or intervention to ensure these enterprises behave in a financially responsible fashion. The growth in arrears by the metallurgy industry also needs attention and may warrant such actions as the discontinuation of supplies. In summary, Naftogaz should accord considerable priority to developing and implementing a program to bring current payment levels up to 100% while also working with appropriate government agencies to help fashion an overall plan to deal with accumulated payment arrears in the energy sector.

52. As part of the process of achieving financial viability for Naftogaz, a close examination of Naftogaz' cost structure will also be required. This examination should include an assessment of measures to improve operating costs and efficiencies. Table 7 which summarizes Ukraine's gas balance points to the fact that almost 9 BCM of gas is used to meet the sector's own operational needs. With gas at the margin valued at import parity levels, this represents a cost factor of almost $450 million. This, therefore is an area where the opportunity for cost savings should be examined. Of immediate note is the fact that about 7 BCM is consumed in transmission. This is a significant level of consumption that, in part, is attributable to the age and inefficiency of the compressor stations. Investment in upgrading the compressors could reduce this consumption level by as much as 2.5 to 3 BCM representing an annual saving on the order of $125 to $150 million. Also of note is the fact that significant commercial losses are incurred. Within

the distribution network these losses amounted to 1.6 BCM in 2002 – an effective cost of $80 million. Reducing consumption associated with transmission and eliminating the commercial losses would greatly improve Naftogaz' financial outlook. A reduction in tax obligations, so that these more appropriately reflect Naftogaz' financial performance, would also assist Naftogaz to achieve financial viability.

53. However, the combination of higher collections, improved operating costs and efficiencies, reduced commercial losses and reduced tax obligations will not be sufficient over the longer term to overcome the economic and financial distortions caused by a tariff structure that does not permit the recovery of the full economic value of the gas being supplied into the domestic market. Consequently, the Government will need to accord high priority to the development and implementation of a gas pricing policy designed to permit full recovery of the economic value of the gas and to create non distorting incentives in the sector.

Pricing Policy Issues

54. The Government of Ukraine will need to address a number of pricing policy issues. The first set of issues deal with appropriate tariff levels for consumers:

- In 2002, it appears that no single category of customer was paying a high enough tariff to cover the full economic value of the gas it consumed (although certain customers may have been covering the financial costs of their gas). In order to achieve full economic value[11] recovery at the 2002 level, tariffs would have to increase, on average, by about 70%. However, households, budget enterprises and CHP and industrial boiler consumers (including JSC Kievenergo) paid substantially less than other consumers, including industry and other electricity generating companies. At present there is no cross-subsidization (whereby certain categories of customer effectively subsidize lower paying customers) since all customers are paying too little; but if the same across the board tariff increase to reach full value and cost recovery levels were introduced, this would have the adverse associated effect of creating cross-subsidization.

- Consequently, while tariffs to all customers need to increase, the impact of the increase would be felt disproportionately by households, budget enterprises and CHP and industrial boiler consumers, if cross-subsidization distortions are to be avoided since their tariffs would need to increase at rates far above 70%. The tariff increase to households, for example, would have to total about 195% to achieve full recovery of the economic value of the gas while avoiding any cross subsidization.

- Increases in gas tariffs to electricity and heat generators would also adversely impact consumer costs for electricity and heat since tariffs for electricity and heat would need to increase if they are also to be fully cost recovering. Again, this effect would be felt disproportionately by households.

[11] This assumes a value of $50/MCM for gas at the border or at the wellhead.

- In order to implement the needed tariff increases with a minimal adverse social impact, social mitigation measures will have to be used. This will have the benefit of converting a broad and very sizeable untargeted implicit subsidy that exists today into a much narrower and more manageable subsidy targeted only to the vulnerable consumer groups. Ukraine has in place a functioning social safety net system that, with respect to gas tariffs, is administered through a household subsidy program. This program suffers, however, from problems of both inclusion and exclusion that need to be resolved. Some time may be required to improve the quality of targeting associated with this system. However, once these issues are addressed and, provided this system is adequately funded, affordability of energy should not be an issue and should not, therefore, be used as an excuse to delay the introduction of a program of phased tariff increases designed to reach full cost recovery levels with gas accorded its true economic value.

- A problem to date has been reluctance within the government to make the additional funds available to the social safety net system to cover needed tariff increases and proposals by both Naftogaz and NERC for higher household tariff levels have been resisted by the government. This is not an insignificant concern. Based on sales to households in 2002, a 195% tariff increase (the level necessary to achieve full recovery of the economic value of the gas) would result in an increased burden on the housing subsidy program on the order of $160 million. Additional funds to cover the payment obligations of the budget funded enterprises would have resulted in a further $40 million tax on the budget. However, increased income tax and VAT attributable to these higher prices would be sufficient to offset the additional costs to the budget (the additional income taxes and VAT strictly attributable to higher prices to households and to budget funded enterprises would have amounted to about $200 million). In addition, Naftogaz' after tax profits would increase significantly (on the order of $500 million) enabling it to address its accumulated tax arrears in addition to having funds available for investment. Consequently, the government could address this social safety net system funding concern by ensuring that a portion of the additional revenues obtained by Naftogaz are used to make a payment to the budget (to meet the additional tax obligations and, possibly also as a payment against tax arrears), thereby ensuring that additional cash is available for social assistance.

55. The second set of issues addresses the question of the appropriate price for domestically produced gas.

- The Ukraine market has access to essentially three sources of gas: domestic production, transit fee gas supplied by Russia and purchased gas which will be supplied via the unified gas supply system (UGSS) of Russia whether it originates from Turkmenistan, Uzbekistan, Kazakhstan or Russia. This establishes the basis for potential gas-to-gas competition, with major consumers in Ukraine (industrial concerns, electricity and heat generation companies, gas distribution companies etc.)

purchasing gas under bilateral arrangements[12], or through a wholesale market governed by competitive rules. In such a competitive market-based environment, the prices of domestic gas production would rise to a level at parity with the import alternatives.

- In an environment, however, where Naftogaz effectively controls supply, this competitive benchmark does not exist. Furthermore with regulated prices to households and to budget funded enterprises being set by NERC on the basis of the cost of domestic production, Naftogaz is effectively prevented from realizing the true economic value of this domestic gas production.

- Under-pricing of domestic gas has a number of consequences:

    i. It distorts the incentives associated with producing operations;
    ii. It acts as a constraint to new investors potentially interested in the sector (this issue is discussed further in the next section of the report);
    iii. It could create fiscal anomalies until the tax structure is modified to conform with good industry practice; and
    iv. It does not provide the proper incentives to consumers to conserve gas usage.

- This all argues for introducing a system that ensures domestic gas is priced at competitive levels in a transparent fashion. There are various ways of achieving this objective:

    i. Establish an element of gas-to- gas competition by allowing large consumers to negotiate purchases from domestic producing entities (a number of these entities are currently part of the Naftogaz corporate structure) as well as from Naftogaz, the holding company, and from import supply sources. Arrangements involving licensed traders had, in theory, allowed an element of gas-to-gas competition, although they became somewhat discredited and have now been essentially eliminated. The key difference here, however, is the prospect of permitting domestic producing entities to negotiate their own sale arrangements.
    ii. All gas supplies could be routed through a wholesale market. Past attempts, however, to use an auction mechanism to establish a pricing benchmark did not prove successful and were abandoned. The auction mechanism did not gain the necessary support from the key stakeholders. In the future, should the likely views of the key stakeholders change this option could once again be considered.
    iii. In the event Naftogaz retains control of a substantial portion of gas supplies, a regulated approach linking domestic prices to calculated import parity could be introduced.

[12] This pre-supposes that the issue of under-pricing gas to households, budget funded enterprises and combined heat and power plants is resolved.

56. The third set of issues address the question of how prices should be set.

- In part, this has been covered under the discussion above about pricing of domestic gas production. In a truly competitive market environment, gas prices can be established by the market. However, where a monopoly situation exists, prices need to be subject to regulatory oversight.

- NERC currently regulates prices for households and state budget enterprises and has been authorized by the Government to set tariffs for industrial customers. Tariffs for CHPs (i.e. heat and electricity suppliers) and for electricity generation companies, however, are not regulated.

- Products supplied through local distribution companies come under what is effectively a "natural monopoly" situation (as do transportation tariffs associated with the transmission line). Larger consumers who have direct access to alternative suppliers would not encounter a monopoly situation provided the alternative suppliers have unrestricted access to the transportation networks. At present, however, Naftogaz has de facto monopoly control of gas supplies. Consequently, all gas customers are, at present, effectively dependent on monopoly supplies which should be subject to regulatory oversight as long as this situation continues.

- Until such time, therefore, as competitive elements are introduced into the Ukrainian market, NERC should have oversight responsibility for setting of all retail tariffs as well as intra-Ukraine transmission tariffs. A "cost plus" approach is standard for tariff setting and would be appropriate in Ukraine. However, in an environment controlled by a single monopoly, there are legitimate concerns about assuring adequate incentives to promote operating efficiency. In an environment where, for example, there a number of distribution companies, a benchmarking approach can be used to encourage efforts to control costs. Absent such an element of quasi competition, a regulator may be forced to use external benchmarks. In the case of Naftogaz, the options are (i) to create an element of quasi competition by requiring that distribution activities be separated from production and transmission activities and then managed and accounted for separately, or (ii) to use external cost benchmarks to assess whether tariff levels and requested increases are appropriate.

- The issue of quality needs to be addressed in conjunction with the issue of price. Consumers are understandably reluctant to pay higher prices in an environment of deteriorating service quality. Consequently, NERC needs to establish a set of quality standards for gas delivery services and then monitor performance against these standards. Within this context, the pricing regulatory process also needs to build in linkages to quality of service.

- Tariffs for transmission and distribution should be calculated separately on a cost plus basis[13]. NERC also needs to consider whether the "postage stamp" approach to

[13] At present there is a single combined tariffs for high and low pressure transporting companies.

transportation tariffs within the country is appropriate given the size of the country and its transmission grid.

Tax Arrears

57. As has already been noted, Naftogaz is the largest tax debtor in Ukraine and has accumulated tax arrears that totaled about 4.6 billion UAH (equivalent to $0.85 billion) at the end of 2002. Absent an increase in tariffs to full economic value recovery levels, Naftogaz will be unable to repay these arrears and there is a risk that the arrears will continue to mount.

58. The immediate concern to be addressed is the issue of how to prevent Naftogaz from accumulating further tax arrears. An underlying principle of effective taxation is that, to the greatest extent possible, the tax system should ensure that enterprises (or projects) that show positive financial results pre-tax[14] should also show positive financial results post-tax. A tax system that produces this result is called "neutral". Full neutrality is often difficult to achieve, but it remains an important tax objective. The concept of progressive taxation in which there is a positive correlation between government take and the underlying profitability of an enterprise (or project) is a widely accepted approach. On the other hand, a regressive system of taxation whereby the government's percentage share of the economic rent increases as profitability declines should be avoided.

59. A simplified presentation of pre-tax cash flows suggests that, even with average prices well below true economic costs, Naftagaz does generate close to break-even cash flows from its gas related operations.

Table 12
Simplified Naftogaz Gas Related Operating Cash Flow ($ Millions)

	Calculation Assumption	2001	2002
Sources of Funds	Net collections (excluding VAT)	1,378	1,288
Uses of Funds:			
Domestic production	$ 17.00/MCM of domestic production	(300)	(300)
Transit line costs	$ 3.47/MCM in 2001, $ 3.50/MCM in 2002[15]	(426)	(418)
Transit payments to budget	$ 0.29/MCM/100 kilometers of transit volume	(392)	(381)
Domestic T&D costs	Per NERC advice[16] (reflects Bank estimates)	(215)	(228)
Total Costs		(1,333)	(1,327)
Cash flow before debt service and taxes		45	(29)

Source: World Bank estimates

[14] Certain payments such as production royalties and, in the case of Naftogaz, pipeline transit fee payments to the budget would normally be deemed "expenses" rather than "taxes" and should, therefore, be included in the "pre-tax" calculation of financial viability.
[15] Source: IMF data.
[16] Equivalent to $5.10/MCM delivered to customers in 2001 and $5.39/MCM in 2002.

60. Bringing tariffs up to full economic recovery levels would, as earlier noted, improve these cash flows by about $1 billion per year. Absent such increases, two options exist to ensure that Naftogaz does not accumulate additional current tax arrears:

i. Changes in the tax system to ensure that it is less regressive in nature (i.e. to minimize non profit-related taxes) could achieve the result of stemming the accumulation of tax arrears. However, as the 2001 and 2002 simplified cash flow numbers show, Naftogaz will remain exposed to potential losses if revenues do not improve and if operating costs increase.

ii. The government could provide a transfer to Naftogaz from the budget to compensate it for the shortfall in tariffs relative to economic costs. Within this context, a few observations are warranted:

- Budget funded enterprises currently benefit, along with households, from the lowest level of tariffs. While the State has an obligation to fund such enterprises there is no logic to having Naftogaz, in effect, pay part of the cost of these enterprises through low tariffs.
- Households also benefit from tariffs that are below the economic value of the gas. Again, it seems inappropriate that the cost of this subsidy should be provided by Naftogaz.
- Similar logic applies in respect of the deliveries of gas to CHPs. There is a knock-on effect in holding down the cost of heat to households, but any required subsidy should be provided by the Government rather than by Naftogaz.

The size of transfers that could have been provided to Naftogaz in 2001 and 2002 is shown in Table 13 below.

Table 13
Potential Transfers

2001	Volume BCM	Tariff Shortfall	Collections %	Potential Transfer ($ mm)
Budget Enterprises	911	$ 23.74	89 %	$ 19.3
Households	15,426	$ 33.05	92 %	$ 469.0
CHPs	9,258	$ 21.88	84 %	$ 170.2
Kievenergo	3,747	$ 18.08	92 %	$ 62.3
Total				$ 720.8
2002				
Budget Enterprises	922	$ 23.01	96 %	$ 20.4
Households	15,492	$ 32.39	97 %	$ 486.7
CHPs	9,421	$ 21.13	78 %	$ 155.3
Kievenergo	3,358	$ 14.55	82 %	$ 40.1
Total				$ 702.5

61. In considering the issue of tax arrears, the key issue to be addressed is who should ultimately absorb the cost of paying for these arrears. Several possibilities exist independently or in combination:

i. The State can absorb the cost by writing off the arrears. The impact will materialize in the form of smaller payments to the budget.

ii. The company can absorb the cost by using future profits to pay down its obligations. With tariffs at or approaching full economic recovery levels and with a high level of collections, Naftogaz will be capable of paying off the accumulated arrears over time. The impact would be felt in the form of lower dividends to its owners, i.e. the State as and when such dividends are paid.

iii. The third option is to recover these arrears from future consumers through higher tariff levels. This, however, would mean raising tariffs above the levels necessary to achieve the full recovery of the economic value of the gas.

62. As an alternative to higher tariffs, the use of a transfer mechanism, as described above, could be implemented to address arrears as well as current obligations.

63. Implicit in the above discussion of tax arrears is the assumption that Naftogaz will meet its payment obligations to its gas suppliers (i.e. Russia, Turkmenistan etc.). In 2001 and 2002 it appears that Naftogaz was capable of generating sufficient cash flow to meet these obligations. In 2003, the arrangement that permits Naftogaz to re-export gas earning an attractive margin on the re-export volumes will help the company's cash flow outlook[17] in 2003 and as long as such exports are possible with a positive margin. However, the possibility that cash flow may not be sufficient in the future to meet all Naftogaz' obligations underscores the need to increase domestic gas prices.

Conclusions and Recommendations

64. Naftogaz has made significant progress in dealing with gas collections. However, while there is still some potential for further collections improvement, particularly from heat enterprises, the primary issue to be addressed if the gas sector is to achieve and sustain financial viability is that of bringing tariff levels up to the point where they achieve full recovery of the economic value of the gas being provided.

65. Increasing tariffs to full cost recovery levels will provide the sector with sufficient revenues to fund needed investment programs. It will enhance the prospects for increased investor and lender interest in the sector (this issue is discussed in more detail later in the report). It will also provide a foundation for addressing both current and accumulated tax arrears. However, a program to increase tariffs will only be fully effective if measures are taken (i) to address the associated social consequences by fully funding the social assistance system; (ii) to deal with monopoly concerns, and (iii) to

[17] It is projected that Naftogaz will re-export about 7.5 BCM of gas to markets in Europe in 2003.

generate consumer acceptance. The Bank would, therefore recommend the following course of action:

i. Ukraine should develop and implement a medium term tariff policy designed to bring gas tariffs up to full economic value recovery levels. This policy should reflect the following principles:
   - A "cost plus" methodology should be employed. This methodology, however, should be based on the economic value attributable to all the gas (i.e. $50/MCM at present) not strictly on costs associated with the acquisition of imported gas (about $50/MCM) and production of domestic gas (about $17/MCM). This will require full disclosure and review of Naftogaz' costs of operation.
   - The plan should avoid the introduction of cross-subsidization (e.g. of households by industrial customers) since this will ultimately lead to the need for tariff rebalancing and may negatively affect industrial competitiveness.
   - The timing of tariff increases to households should be cognizant of the fact that the existing social safety net is capable of addressing affordability concerns but needs to be modified to ensure better targeting. The social safety net also needs to be fully funded to deal with the consequences of higher gas prices. However, the additional tax revenues attributable to these higher prices, together with the prospect of some payment by Naftogaz of tax arrears, should provide more than adequate revenues to cover these additional funding needs.
   - While the plan will need initially to address Naftogaz' current monopoly position[18] in the market, provision should be made for a transition to a more competitive market environment (e.g. in the form of gas to gas competition that allows bi-lateral contracts and/or through the introduction of a wholesale market).

ii. As long as Naftogaz retains monopoly control over the gas sector, increased regulatory oversight will be required. NERC should play a key role in the development of the medium term tariff policy. It should also be assigned oversight responsibility for all gas prices until such time as a level of genuine gas to gas competition is introduced that will allow the market to set prices to certain categories of customers.

iii. Prior to the introduction of full cost recovery tariffs for budget enterprises, households and CHP facilities, the government should introduce a mechanism to compensate Naftogaz for the implicit subsidy it is being required to provide. This compensation can, perhaps most easily, be provided in the form of a transfer from the budget designed to reflect the equivalence of Naftogaz being able to charge a full cost recovery price.

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[18] The issue of Naftogaz' monopoly role will be discussed in more detail later in the report.

iv. The compensation mechanism provided to Naftogaz (as proposed in iii above) should allow Naftogaz to handle any shortfall in tax payments attributable to the implicit subsidies it is providing and should allow it, over time, to clear its accumulated tax arrears.

v. While resolution of the tariff shortfall should be accorded high priority, Naftogaz, with full government support, should continue to focus on improving collections. This may require changes in management and/or ownership of delinquent enterprises and the application of severe sanctions including disconnection.

vi. As a matter of urgency, Naftogaz also needs to address the level of commercial losses being incurred and needs to undertake a comprehensive review of its cost structure with the objective of achieving reductions in own use consumption of gas and in the other costs of its operation.

Funding the Investment Requirements Of the Gas Sector

Investment Needs

66. Ukraine, is heavily dependent on gas which makes up almost 50% of its primary fuel consumption. (Ukraine also imports over 40% of its primary fuel requirements and gas makes up the bulk of these imports). Consequently, the performance of the gas sector has a potentially significant impact on the economy as a whole.

Table 14
Production and Consumption of Primary Fuels – 2002

Million TOE[19]	Gas	Oil	Coal	Nuclear	Hydro	Total
Production	15.5	0.9	43.0	17.7[20]	2.2	79.3
Consumption	62.8	12.9	38.3	17.7	2.2	133.9

Source: BP Statistical Review of World Energy 2003

67. Ukraine has very significant investment needs if it is to achieve the objectives of (i) maintaining domestic gas infrastructure, (ii) maximizing the benefit to be obtained from the gas transit line and (iii) optimally exploiting its gas resource base.

Table 15
Ukraine's Gas Network[21]

Gas Transmission:	
Transmission pipelines	37,100 km
Import capacity	290 BCM
Export capacity	170 BCM
Number of compressor stations	72
Compressor capacity	5,600 MW
Gas Storage:	
Number of facilities	13
Capacity	30 BCM
Gas Distribution:	
Distribution pipelines	163,000 km
Number of distribution companies	46

Source: Naftogaz

68. As Table 15 indicates, Ukraine's gas network is extensive. However, since independence, a shortfall in investment in gas transmission and distribution infrastructure has led to a deterioration in the quality of this infrastructure. This deterioration needs to be reversed through a program of rehabilitation. These rehabilitation needs include rehabilitation of the gas transit pipeline system, a key strategic asset, (which is part of the

[19] TOE is Tons of Oil Equivalent.
[20] The uranium supplies for the nuclear plants are all imported so, although the power is produced from domestic facilities, the primary underlying fuel source is not.
[21] As of January 1, 2002.

gas transmission network). Further investment will be required to upgrade and, as appropriate, expand the network. Key elements in these further requirements are (i) expansion of the gas transit system from its current effective capacity level of about 170 BCM (of which146 BCM exists at the western border) to a level of 200 BCM/year and (ii) the installation of metering with the objective of eventually metering all customers.

Table 16
Projected Capital Investment Requirements

$ Millions	2003	2004	2005	2010
Gas Transmission System Rehabilitation	357.0	383.6	344.9	277.5
Gas Transit Line Expansion	618.2	368.0	351.0	2.1

Source: Naftogaz

69. As Table 16 indicates, rehabilitation investment needs for the gas transmission system (including the transit pipeline) are estimated in the range of $300 to $400 million per year over the next several years, while expansion of the transit line is expected to require investments well in excess of $1 billion. There has also been discussion about construction of a new 28 BCM transit line which would cost on the order of $1.5 to $2 billion. Investment requirements to rehabilitate the distribution system will likely be similar to those for the transmission system.

70. In addition, significant investment is required if the full potential of the underlying hydrocarbon resource base is to be effectively exploited. Given Ukraine's dependence on gas imports, increases in domestic gas production will clearly have a positive impact on Ukraine's energy trade balance.

71. Naftogaz own projections (Table 17) do indicate some increase in domestic gas production and Naftogaz has suggested that production could be increased by as much as 10 to 12 BCM/year. However, the size of Ukraine' proved reserve base suggests that there is scope for larger increases in domestic gas production levels and some industry estimates, therefore, are higher than the Naftogaz estimate. The critical constraint, however, is access to capital. A production increase of 10 BCM/year from proved reserves would require capital investments of as much as $1.5 billion[22] and Ukraine simply does not have the internal capacity to generate these investment funds. Consequently, if Ukraine is to maximize the value from its gas resource base (while maintaining the rest of the sector as a viable operation) it will need access to external capital in the form of investments and/or loans. This, in turn, will require that Ukraine establish and maintain an attractive climate for investment in the sector.

Table 17
Naftogaz' Natural Gas Production Projections

Year	2002	2003	2004	2005	2010
Production (BCM)	18.8	19.1	20.2	21.3	24.5

Source: Naftogaz

[22] Capital costs for the discovery and development of new reserves would be substantially higher.

Creating an Attractive Investment Climate

72. The level of foreign direct investment inflows into a country is a key indicator as to how attractive an investment climate exists within the country. In the case of Ukraine, given the size of the economy, the level of foreign direct investment is very low.

Table 18
Foreign Direct Investment in FSU Countries

$ Million	Avg. FDI 1997-2001	FDI as % 2001 GDP	$ Million	Avg. FDI 1997-2001	FDI as % 2001 GDP
Armenia	137	6.87 %	Lithuania	518	4.39 %
Azerbaijan	604	11.39 %	Moldova	96	6.37 %
Belarus	252	2.08 %	Russia	3,238	1.04 %
Estonia	416	7.84 %	Tajikistan	22	1.96 %
Georgia	176	5.68 %	Turkmenistan	108	1.80 %
Kazakhstan	1,769	7.83 %	**Ukraine**	**646**	**1.72 %**
Kyrgyz	55	3.65 %	Uzbekistan	114	1.01 %
Latvia	367	4.89 %	Total FSU	8,517	1.94 %

Source: World Bank analysis

73. Table 18 compares average annual FDI inflows for the five year period 1997 to 2001 with 2001 GDP levels in each of the FSU countries. On the basis of this ratio, Ukraine lags all the FSU countries with the exception of Russia (which has benefited from a high level of domestic investment) and Uzbekistan. The countries in the forefront of attracting FDI during this period are Azerbaijan and Kazakhstan which have opened up their upstream petroleum sectors to international investors under acceptable terms and conditions.

74. In general, countries with mineral and petroleum resources (the extractive industries – mining and petroleum) are most easily able to attract FDI. If they are unable to do so, other sectors generally have problems attracting FDI. Consequently, when looking at the investment climate in Ukraine, one of the first areas to consider is the upstream petroleum sector.

75. Producing countries are currently forced to compete for access to investment capital for the oil and gas sectors. Four key factors come into play in the decision process that investors undertake:

i. Geology which will dictate the potential size and complexity of developments and will have a substantial influence on costs;
ii. Geography which will influence both producing costs and the costs of transporting hydrocarbons to market;
iii. Geopolitics which will influence the risk assessment of the project; and
iv. The investment climate in the host country which will have a significant effect on the perception of the financial risks associated with the project.

76. Host governments can do nothing about geology or geography. They can and do help create the geopolitical environment, but cannot fully control it. However, they do have full control over the creation of the investment climate for the oil and gas sectors.

77. In creating an overall environment that will attract investors, the impact of geology, geography and geopolitics have to be considered and reflected in the terms that are negotiated. Such negotiation, however, will run more smoothly and will ultimately deliver greater benefits to the host state if the government has adhered to a number of key principles.

78. These key principles are summarized in Box 2 below. Although these principles are not uniformly weighted, they all have significant bearing on perceptions of the overall climate for investment. Insofar as Ukraine is concerned the most critical issues to be addressed are (i) the legal and regulatory environment, (ii) access to markets (and, associated with this the functioning of the domestic marketplace); and (iii) Naftogaz' current monopoly status within the oil and gas sectors.

Box 2 - Creating an Attractive Climate for Oil and Gas Investment

i. Do not impose a punitive or regressive tax regime;
ii. Introduce an acceptable legal framework;
iii. Provide supporting regulations administered by an independent and impartial regulator;
iv. Create an environment that facilitates assured non discriminatory access to markets;
v. Do not interfere with the functioning of the marketplace;
vi. Do not discriminate among investors;
vii. Honor internationally accepted standards;
viii. Abide by contractual undertakings and preclude the use of an administrative bureaucracy to constrain investor activity;
ix. Prevent monopoly abuses;
x. Ensure the sector's operations are transparent and free of corruption.

The Legal and Regulatory Environment

79. An acceptable legal framework will adequately protect the interests of both the State and the investor. Its main purposes are:

i. To provide the basic context for and rules governing oil and gas operations in the host country;
ii. To regulate oil and gas operations as they are carried out by both domestic and foreign enterprises;
iii. To define the principal administrative, economic and fiscal guidelines for investment activity in the oil and gas sectors.

80. In many countries, the lynchpin of a legal framework is a Petroleum Law[23]. However, in many transition and developing economies, investors insist upon a contract based approach – with production sharing agreements (PSAs) often being the preferred approach, and investors are often prepared to forego the existence of an acceptable Petroleum Law provided their PSAs are given the full force of law.

81. Within Ukraine, legislative actions are well on track. The Law on Production Sharing Agreements was adopted in September 1999; enabling legislation was passed in July 2000 and a number of associated regulations have been enacted. In addition, the Law on Oil and Gas was adopted in July 2001. The fiscal terms in the PSA Law are broadly acceptable, although clarification is required on such items as (i) the tax treatment of pre-production intangible capital costs; (ii) abandonment costs; (iii) investor head office's general and administrative costs; and (iv) interest on financing. The main outstanding actions associated with the PSA regime are the completion of the enactment of required regulations.

82. Regulatory responsibility for the gas sector was assigned in 1998 to the National Electricity Regulatory Commission (NERC). However, responsibility for upstream petroleum sector licenses is handled by the Ministry of Environment.

Box 3 - The Purpose of Regulation

"The fundamental purpose of Regulation is to protect customers from a private monopoly company abusing its position and charging too high prices and/or giving poor service to its captive customers. If a Regulator succeeds in getting the prices right for all customers so they are equivalent to those that would work in a competitive market, the signals for investment and for demand for gas overall, and relative to other fuels will also be right. This will give the correct signals for supply of gas over the longer term.

A monopoly company does not have to be efficient, and a major role for the Regulator is ensuring that management is put under pressure to be both efficient and innovative. A monopoly company will aim to make monopoly profits at the expense of customers by charging too high prices and by not providing a good service. All these tendencies can give rise to significant costs to the economy unless the industry is well regulated.

In an industry as important as energy, where supply is currently a monopoly, effective regulation can have a significant impact on the economy as a whole. This is both because the natural inefficiencies of a monopoly throws potential wealth away, but, perhaps even more importantly, the incorrect signaling of prices gives the wrong incentives for investment across the whole economy."

Gas Strategies

[23] In some cases separate Oil and Gas Laws.

83. Ukraine has also prepared a draft Law on the Principles of Operation of the Natural Gas Market. The intention of the draft law is to promote good management of the sector and to encourage competition. Its provisions include:

- Defining oversight responsibilities for the gas sector;
- Outlining the roles and responsibilities of the regulator, NERC, (although the obligation to establish and monitor quality standards is not included);
- Providing for non discriminatory access to the gas transmission system (although the proposed law allow does not mandate the addition of capacity when shippers would be willing to cover the investment cost);
- Stipulating that prices will only be regulated for those categories of customers designated by the Cabinet of Ministers;
- Entitling customers to choose their own suppliers; and
- Outlining the rights and obligations of customers, suppliers, shippers and transmission and distribution pipeline operators.

Once enacted, this law should be a positive addition to the legislative framework.

84. As the statement in Box 3 indicates, effective regulation is critical to the economy as a whole. It also has a significant impact on investor and lender perceptions since the Regulator is key to ensuring a level playing field for all the players. In undertaking its role, therefore, NERC should be accorded whatever government support may be required to ensure that its performance can conform to good international practice.

Access to Gas Markets and Pricing

85. While some work is required to clarify and strengthen the legal and regulatory environment, investor concerns are likely to be focused more strongly on the issues of access to attractive petroleum prospects and access to acceptable gas markets and pricing within those markets.

86. The issue of access to attractive petroleum prospects is a precursor to consideration of other factors affecting the investment climate. If reasonable exploration and development prospects are not made available, there will be little investor interest regardless of how attractive other elements of the investment climate may be. The attractiveness of such prospects, however, is also significantly impacted by the attractiveness of the markets that can be accessed and the prices achievable in those markets.

87. Ukraine is connected to the European gas grid and the primary initial interest of potential investors would be directed to the possibility of accessing the Western European market. However, agreements with Gazprom impose restrictions on access to these markets through the existing high pressure transmission system[24]. Consequently, until such time as either (i) access is provided for Ukrainian gas producers to the existing

[24] The European Union has taken exception to this provision which it deems to be a restraint of trade. As a result, it is reported that when Poland, an EU accession candidate, recently renegotiated its gas supply and transportation contracts with Gazprom it succeeded in having the clause removed that prohibited the export of indigenous production and the resale of import purchases.

export line (either with its present capacity or with expanded capacity), or (ii) alternative export options are available to Ukrainian producers, these producers will be limited to the domestic market.

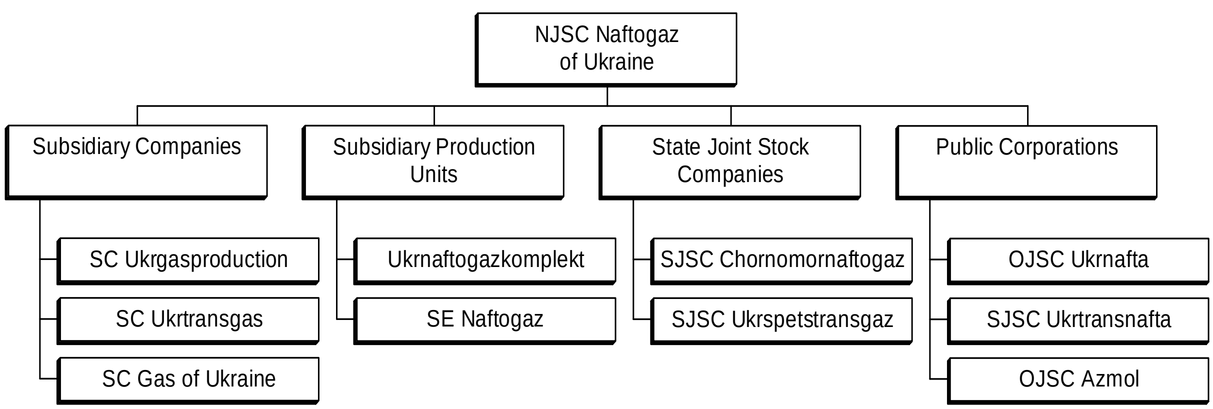
88. Naftogaz today controls domestic production, all gas transmission and storage and parts of the distribution network. Any investor in the gas sector is, therefore, going to have to deal with Naftogaz. In addition, any investor is faced, at present, with a pricing structure in the domestic market that, on average, results in prices that are below import parity and that are well below netback price levels for sales into the Western European market.

89. Faced with a controlled low price environment and the need to deal with a powerful monopoly enterprise, it is not surprising that strategic investor interest in the gas sector has been very limited. However, even within the existing monopoly structure of the Ukrainian gas sector, measures can be introduced that will promote some additional level of investor interest.

The Structure of Naftogaz

90. The current organization structure of Naftogaz is shown in Figure 3:

Figure 3
General Organization of Naftogaz



Source: Naftogaz presentation

As this chart indicates, the structure is essentially that of a holding company.

91. The simplest means of reducing investor concerns about Naftogaz' monopoly status and the lack of competition in the gas sector would be to unbundle Naftogaz both vertically (i.e. by separating production, transmission, storage and distribution) and horizontally (i.e. by setting up a series of competing production companies). This was one of the options considered in 1997. However, an improvement in the competitive

environment and in investor perceptions can also be achieved without a full physicial unbundling of Naftogaz' assets but rather with a "virtual unbundling"[25].

92. A "virtual unbundling" would require a series of parallel actions, but would allow Naftogaz to retain a role as a holding company and to retain an interest in all gas sector operations in Ukraine. These actions are as follows:

i. The subsidiary production units would need to be separated into discrete companies (and possibly established as separate joint stock companies) with the objective of establishing competing enterprises.

ii. All of Naftogaz subsidiary operations (whether classified as subsidiary companies, subsidiary production units, joint stock companies or public corporations) would need to be granted financial and managerial autonomy (along the lines currently enjoyed by Chornomornaftogaz).

iii. As autonomous organizations, each subsidiary would be expected to function as an independent commercial enterprise. This would involve:
- The preparation and implementation of business plans for each individual enterprise.
- The preparation and maintenance of independent accounts (which should be established in accordance with international accounting standards – see the further discussion below).
- Management autonomy through the establishment and empowerment of separate management structures and separate Boards of Directors.
- The introduction of arms length commercial arrangements for the sale and purchase of gas among affiliated companies.
- A review and approval mechanism for capital programs and for the enterprise's dividend policy.

iv. At the same time, all the subsidiary companies would have an obligation to report financial and operating results to the holding company parent, both to allow for the preparation of consolidated results for the group and to enable the holding company to exercise its oversight rights as a shareholder of the various subsidiaries[26].

93. Naftogaz need not retain the same level of shareholding in the various subsidiary companies – equity interests could range from 100% to a minority share, but would still allow Naftogaz (and through Naftogaz the State) to retain an interest in the activities of

[25] It is also worth noting that a physical unbundling of Naftogaz before all issues related to payment discipline, debt and financial arrears are resolved could be counter-productive. Experience elsewhere has indicated that unbundling a state owned enterprise before the issue of arrears is addressed greatly complicates the ultimate resolution of this issue. This argues for initially focusing on a "virtual unbundling" of Naftogaz rather than a physical unbundling.

[26] At present Naftogaz has some difficulty in securing necessary financial and operating information from certain subsidiary enterprises.

each enterprise. Indications that this type of approach would have the potential to attract investor interest are provided by the external interest that has been generated in Chernomornaftogaz.

The Potential for Commercial Borrowing

94. Certain of the features that are necessary to attract investor interest to the gas sector are also essential if Naftogaz and its subsidiaries are to be able to secure financing under commercial terms.

95. The primary concern of any potential lender is the financial viability of the enterprise seeking to borrow. As a result, potential lenders will have a particular interest in an enterprise's financial statements which should, ideally, be provided in the form of audited accounts prepared in accordance with international accounting standards.

96. More broadly, it would be desirable if Naftogaz and its subsidiaries were to meet the disclosure standards that represent best practice among national oil and gas companies – Statoil of Norway and PetroCanada of Canada are representative of best practice among such companies.

Box 4
Transparency Requirements for National Oil and Gas Companies

Disclosure Requirements to the General Public:

Minimum requirements are those that pertain to a publicly quoted major oil and gas company:

- Annual financial statements (which should be prepared in accordance with international accounting standards) for the consolidated operation and its major business units.
- Quarterly interim financial statements.
- Statistics on operating performance.

Disclosure to the Government:

The Government has a valid basis for seeking disclosure of any information it requires to ensure that these state owned assets are being efficiently managed.

Disclosure to Lenders:

- Detailed financial information (including, ideally, accounting statements audited in accordance with international accounting standards).
- Project specifics (in the case of project financing).

Disclosure to the Regulatory Authority:

Information required to allow the Regulator to make a determination of appropriate tariff levels and compliance with service standards e.g.:

- Detailed accounts
- Operating costs
- Actual and projected capital costs
- Administrative and general cost
- Borrowing costs
- Customer data
- Physical data
- Quality of service indicators
- Any other data deemed pertinent to the decision process*

*Confidential information may be requested by the Regulator, but may not be disclosed by it.

97. Transparency has a number of benefits. It promotes efficiency by subjecting the company and its management to scrutiny by its stakeholders, including comparisons with other oil and gas companies. It acts as a deterrent to corruption and it lowers the cost of capital by encouraging investment and lowering borrowing costs[27]. Box 4 above summarizes the key transparency requirements for Naftogaz and its subsidiaries.

Conformity with the EU Gas Directives

98. In considering the future structure of its gas sector, Ukraine should remain cognizant of the provisions of the EU Gas Directives and any future amendments. Conforming the Ukrainian gas sector structure to the EU Gas Directives will facilitate trading and other relations with the EU. Key provisions of the EU Gas Directives and of amendments under consideration are detailed below.

99. On June 22, 1998, the European Parliament and the Council adopted Directive 98/30/EC concerning common rules on storage, transmission, supply and distribution of natural gas. On June 26, 2003, Directive 03/55/EC was adopted which initially supplements and as of July 1, 2004 will supersede Directive 98/30/EC A summary of the provisions of these Directives that are particularly relevant to Ukraine is given in Box 5 below.

[27] Potential lenders will charge a premium in the event there are concerns about the transparency since this translates into a perception that required financial information may not be disclosed in full.

Box 5
Key Provisions of Directives 98/30/EC and 03/55/EC

Access to the market. One of the key objectives of the Directives is to open up the gas market within Europe. Within this context, the Directives have a number of provisions intended to assure suppliers non discriminatory access to the market. These include:

i. The use of non discriminatory criteria in issuing authorizations (e.g. licenses, permits, concessions etc.) to operate natural gas facilities;
ii. A requirement that there be no discrimination between system users or classes of system users in using transmission, storage and distribution facilities;
iii. Assurances that there will be no discrimination among users in respect of the application of regulated tariffs.

Opening up the market. In order to open up the market, Member States are required to allow freedom of supply choice to "eligible customers". "Eligible customers" are initially defined as:

i. Gas fired power generators, irrespective of their annual consumption level;
ii. Other final customers consuming more than 25 million cubic meters of gas per year on a consumption-site basis.
iii. From July 1, 2004 at the latest all non-household customers will be deemed "eligible".
iv. From July 1, 2007 all customers will be deemed "eligible".

Access to the system. The Directives envisage two forms of access to the system:

i. In the case of negotiated access, both suppliers and consumers must be permitted access to the system so as to conclude supply contracts with each other.
ii. In the case of regulated access, use of the system is based on published tariffs and terms for the use of the system.

Transparency. The Directives place particular emphasis on transparency within the sector. Requirements include:

i. Publication of non-discriminatory criteria and procedures for granting authorizations to operate natural gas facilities;
ii. Natural gas undertakings are required to publish their annual accounts or make them available to the public at their head office;
iii. Integrated natural gas undertakings are required to keep separate accounts for their natural gas transmission, distribution and transmission activities. These accounts must include a balance sheet and profit and loss account for each activity.
iv. Directive 03/55/EC further requires the legal unbundling of transmission and distribution system operators.

Regulation and dispute resolution. A number of provisions within the Directives relate to the issues of regulation and dispute resolution:

i. Member States are required to create appropriate and efficient mechanisms for regulation, control and transparency so as to avoid any abuse of a dominant position, in particular to the detriment of consumers, and any predatory behavior.

ii. Member States are required to designate a competent authority, independent of the parties, to settle disputes expeditiously relating to system access.

Member States are required to designate one or more national regulatory authorities that must be vested with the powers to ensure non-discrimination, effective competition and effective functioning of the market.

Conclusions and Recommendations

100. Ukraine has the potential to attract both investor interest and commercial lending to its gas sector[28]. This interest, however, will increase significantly if measures are introduced to make the investment climate in the sector more attractive. These measures include efforts to conform the Ukraine gas sector to the requirements of the EU natural gas Directives.

101. Perhaps the most critical issue will be to ensure that Naftogaz does not act as an impediment to investment. While this can be addressed through a physical unbundling of the sector, it can also be addressed (albeit perhaps not as effectively) through a virtual unbundling of Naftogaz and this may be a more acceptable near term option. The Bank would, therefore, recommend the following course of action:

i. In the area of legislation and regulation, the key actions required are (a) to complete the measures associated with the PSA regime; and (b) to support NERC in establishing a track record in effectively regulating the activities of Naftogaz.

ii. Ukraine should also finalize the draft Law on the Principles of Operation of the Gas Market. Ideally, in its final form, this law should include among the regulator’s responsibilities that of establishing and monitoring quality standards.

iii. Bringing all tariffs up to full cost recovery levels (as was discussed in the previous section) will greatly enhance the attractiveness of the domestic market.

iv. Allowing producers access to export markets either through the allocation of some capacity in the existing transit line (possibly after its capacity is expanded) or by allowing exporters to make their own export arrangements. Such non discriminatory access should be consistent with the provisions of the EU Gas Directives.

[28] This is already evidenced by the investor interest in the gas transit line (see the next section of the report) and in Chernomornaftogaz.

v. An assessment is currently underway of restructuring options for Naftogaz. Efforts should be made, however, to ensure that recommendations implemented as a result of this study are consistent with the goal of attracting additional investor interest in the sector. Part of this process should involve inventorying and ranking exploration and development prospects and then ensuring that some of the more attractive prospects are made available to potential investors[29]. More broadly, within this context, Ukraine will need to assess whether to pursue de facto asset sales, equity sales or joint venture arrangements.

vi. Naftogaz should also embrace best practice transparency requirements for national oil and gas companies both at the holding company and at the subsidiary level. As a first step, this should involve a program to place the entire company on international accounting standards. Measures also need to be introduced requiring all subsidiaries to provide financial and operating performance reports to Naftogaz. Such measures should be consistent with the provisions of the EU Gas Directives.

[29] These could be made available in the form of concessions or PSAs as well as in the form of joint venture arrangements. The key is to ensure that investor interest is generated.

Maximizing the Value of the Gas Transit Arrangements

Gas Transit Performance

102. Ukraine's high pressure gas transit line is a major strategic asset. However, there are risks that this asset will not generate an optimum return on its strategic value in the future. In order to maximize the value from this asset, Ukraine needs to work towards :

i. Convincing Russia that Ukraine should be the preferred transportation route for future increases in gas deliveries to Europe;
ii. Ensuring that the rehabilitation needs of the line are handled;
iii. Expanding capacity to meet potential future demand levels;
iv. Ensuring some capacity is available for exports of Ukrainian gas;
v. Securing transit tariff payments in cash rather than in kind;
vi. Increasing the transparency of gas transit activities by disclosing such arrangements; and
vii. Ensuring that a fair share of transit payments accrue to the State.

103. Table 19 provides details of gas transit levels to CIS countries and to Europe via Ukraine. As the table indicates, transit peaked at 141 BCM in 1998 and has since declined to a level of 120 BCM in 2002. Exports to Europe peaked at 119 BCM in 1999 and in that year Ukraine transited 93.6 percent of Russia's exports outside the FSU. Its share, however, has been shrinking ever since then, although it still amounted to 82.8 percent of Russia's non-FSU exports in 2002.

Table 19
Gas Transit via Ukraine

BCM	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002
To CIS countries	30.0	30.0	29.2	27.5	23.4	24.8	26.2	14.6	11.3	19.1	15.3
To Europe	92.9	93.2	99.7	110.2	116.5	108.4	114.9	118.7	109.3	104.3	104.5
Total Transit	122.9	125.2	128.9	137.7	139.9	133.2	141.1	133.3	120.6	123.4	119.8

Source: Naftogaz

104. The decline in transit levels that occurred after 1998 resulted from Russian perceptions of Ukraine as a "bad transit country". Work undertaken by Professor Paul Stevens of the University of Dundee has led to the identification of a number of characteristics that will determine the likelihood that a country will act as a "good" or a "bad" transit country. Box 6 below lists these characteristics.

Box 6
Defining "Good" and "Bad" Transit Countries

A "good" transit country:	A "bad" transit country:
• Wants and can attract foreign investment	• Rejects/unable to attract foreign investment
• Transit fee unimportant for foreign exchange	• Transit fee important for foreign exchange
• Relatively limited rent availability	• Relatively significant rent availability
• Dependent on line offtake	• Not dependent on line offtake
• One of a number of alternatives	• The only possible export route
• No collusion likely with alternatives	• Collusion likely with alternatives
• Not a competing exporter	• A competing exporter

Source: Professor Paul Stevens, University of Dundee

105. As this list indicates, a number of factors create a pre-disposition for Ukraine to behave as a "bad transit country" and this behavior did materialize in the 1990s in the form of non payments for gas and unauthorized consumption. While this created considerable tensions between Russia and Ukraine it also encouraged Russia to seek to reduce its dependence on Ukrainian transit. The main mechanism for reducing this dependence has been the development of alternative pipeline routes:

i. The **Yamal** pipeline established Belarus and Poland as a second major export corridor for Russian gas to Western Europe and this now functions as a key alternative to the traditional export route through Ukraine, Slovakia and the Czech Republic. This pipeline now has a capacity of about 20 BCM/year with two out of the five compressor stations in Poland operational. When the remaining three compressor stations are completed by the end of 2004, the pipeline's capacity will be increased to 33 BCM/year. The Yamal-Europe pipeline began shipping sizable volumes in September 1999, when the first section of the Belarussian section of the line was completed and there was a consequent reduction in the volumes shipped via Ukraine.

ii. The **Blue Stream** pipeline crosses the Black Sea from Russia to Turkey. The first phase of the line (with a capacity of 8 BCM/year) came on stream at the end of 2002. The second phase which will increase capacity to 16 BCM/year is under construction. This line was designed to deliver gas to the Turkish market. Turkey, however, has substantially over-committed to gas purchases with supplies coming from Russia (both via transit through Ukraine and via Blue Stream), Iran, Nigeria (as LNG) and Algeria (as LNG). In addition, plans are underway for imports of gas from Azerbaijan. Turkey is now actively looking at constructing a pipeline to Greece in order to re-export some of this gas. This means there is a very real possibility that, at some future stage, the Blue Stream route could be used to transport gas to Europe. It also appears quite possible that Turkey will not extend, in its entirety (if at all), the contract for Russia to deliver 14 BCM/year, via the Ukraine transit line, when it expires in 2011.

iii. Gazprom has announced plans to construct the **North Transgas** pipeline to connect Russia and Germany via the Barents Sea. This line, which has an

estimated construction cost of $5.7 billion, is still very much in the planning stage, but will probably eventually be built.

106. The second mechanism to reduce Russian exposure associated with gas transit of Ukraine was employed by Gazprom which permitted the gas trading company Itera to take over arrangements to supply Ukraine and allowed Itera access to Gazprom's transmission system to transport gas purchased by Ukraine from Turkmenistan. This effectively eliminated the non payment risk that Gazprom had previously incurred. Late in 2002, however, Itera was replaced in this trading role by EuralTransGas, a company owned by Hungarian investors but which Gazprom and Naftogaz are interested in jointly acquiring.

Figure 4
The Gas Transmission System of Ukraine

Source: Naftogaz

107. Russia's actions, however, have led to a reduction in transit volumes and have created substantial spare capacity in the Ukraine transit system. The bulk of the transit system consists of 6 major pipelines with a total length of about 8,699 kilometers. These pipelines enter Ukraine from Russia near Sumy and at Novopskov (east of Kharkiv) and exit near Uzhgorod on the border with Slovakia. They each have a design capacity of 28 to 30 BCM/year and Ukraine's delivery capacity to the export point at Uzhgorod is about 120 BCM/year, of which only about 90 BCM is currently being used. Four transit pipelines also extend (via Moldova) to the exit point in Ismael in southwestern Ukraine

near the Romanian border. These provide a delivery capacity at the Romanian border of 25.3 BCM/year[30].

108. The effective operating capacity of the transit pipeline system at the western border is currently estimated at 146 BCM per year. Thus about 40 BCM of spare capacity currently exists. However, there is potential to increase the capacity of the system to about 200 BCM per year, albeit at a capital investment cost well in excess of $1 billion. There have also been discussions about construction of a new 28 BCM pipeline at a cost of about $1.5 billion to $2 billion. Consequently, provided the market demand exists, there is considerable potential for Ukraine to increase gas transit from Russia and, subject to Russia allowing the transit through Russia, from Central Asia.

109. The anticipated growth in gas demand in Europe creates an opportunity for Russia (and possibly also for Central Asian countries exporting gas via Russia) to increase sales into Europe. The supply route through Ukraine offers by far the most cost effective means of delivering additional supplies to Europe. Estimates of the European supply gap after 2010 (i.e. the portion of demand not covered by current contracts or by extending contracts that are scheduled to expire) range from 50 BCM/year to 180 BCM/year[31]. Supplies from Russia and from Central Asia via Russia clearly will not fill the entire gap, but the potential demand could be sufficient to use all the existing transit capacity through Ukraine and a substantial portion of expanded capacity. For Ukraine to secure these additional transit volumes, however, it will have to convince Russia that it will act in the future as a "good transit country".

110. One key measure towards achieving this objective is the decision incorporated in the framework accord of October 2000 between Ukraine and Russia to discuss the establishment of a consortium to rehabilitate and manage the gas pipeline transit system. This accord was followed by a joint declaration executed in June 2002 by Ukraine, Russia and Germany pledging to cooperate in managing Ukraine's transit pipeline system.

111. In the late 1990s, Ukraine had rejected a proposal made by a consortium led by Shell to acquire a 50% stake in the transit line system. It had also rebuffed earlier efforts by Gazprom to persuade Ukraine to transfer operating control to a joint venture. Both the Ukrainians and the Russians, however, have now become convinced that there is merit in moving ahead with the proposal and in, October 2002, Naftogaz and Gazprom signed the "founding documents" for a consortium[32] to manage the gas transit system and the consortium was officially registered in January 2003.

112. Moving ahead with the consortium arrangement offers two potential key benefits to Ukraine. First, it should assure Ukraine of being able to handle the transit arrangements for a significant portion of any additional sales that Russia makes to Europe

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[30] Source: Cambridge Energy Research Associates
[31] World Bank estimates
[32] Although not a party to this agreement, Ruhrgaz of Germany has also expressed interest in participating in this consortium

in the future. Second, it will provide access to sources of funding for both rehabilitation of the existing system and the capital investment to expand the system. However, the proposed arrangement also raises three key issues that the Ukrainian government will need to address to ensure that the State secures the maximum benefit from the arrangement:

i. How should the arrangements for the consortium to manage the transit pipeline be structured?
ii. Who should have access to the pipeline under this new arrangement?
iii. What arrangements should be instituted to ensure that the State of Ukraine receives its fair share of the economic rent associated with the operation of the transit line?

Management of the Transit Pipeline System

113. Ukraine's gas transmission assets are owned by the State Property Fund while Naftogaz has exclusive rights to operate the system. In transferring management responsibility for the transit pipeline system to a consortium, Ukraine has three key issues to address. The first is how the consortium should be composed. The second is whether the consortium should take on management responsibility for just the transit line system (consisting of the lines to Uzhgorod and to Ismael) or whether it should take on responsibility for the entire high pressure transmission system. The third concerns the specific form of the management arrangement.

Composition of the Consortium

114. As has been noted, there has been considerable interest in a consortium arrangement from a number of quarters which may allow Ukraine to press for a shareholding structure that allows it to address a number of issues. The recent discussions have primarily involved Ukraine and Russia, but Ruhrgaz (a minority shareholder in Gazprom) has also been a party to some of the discussions. At the same time it is very possible that Shell and other private sector enterprises that had previously expressed interest in the pipeline may still have an interest.

115. The primary value of having Gazprom involved in the consortium is the prospect that this will improve Russia's perception of Ukraine as a transit country. Projects such as the North Transgas pipeline will eventually be built. What will affect Ukraine is how quickly they are built. Any delay in construction of such a pipeline secures additional transit revenues for Ukraine thus it is very much un Ukraine's interest to be perceived as a "good transit country".

116. Involvement of private sector western companies will reinforce the perception that Ukraine will behave in the future as a "good transit country". In addition such companies offer additional key benefits. First they have expertise that will be of value to the consortium. Second they will provide an additional element of checks and balances since they will insist on the application of best international operating practice and will

insist on transparency in the operation. This will clearly be of benefit to Ukraine. Consequently, as the consortium discussions proceed, Ukraine should seek to ensure that participation by some western private sector enterprises be secured.

What Should be Managed ?

117. The transit line system is a key strategic asset that represents a significant source of earnings for the country and revenues for the budget both currently and in the future. As has been noted, the transit line system is in need of rehabilitation and also has the potential to be expanded, thereby allowing the opportunity to increase overall gas transit revenues. The remainder of the transmission system will not contribute to the trade balance and to the budget in this fashion. It is, however, a key element of the domestic gas sector which needs to be preserved in good operating condition if the domestic gas sector is to function efficiently and effectively. This system, however, is also in need of rehabilitation investment.

118. In reaching a decision on the scope of the management role for the consortium, the government will need to weigh a number of considerations:

i. It will likely be simpler to negotiate the financial terms applicable solely to operation of the transit line system than to the entire transmission network. These issues include valuation of the arrangement and the provision of a share of the economic rent associated with operation of the system to the State budget.
ii. If the consortium is to take over the entire network, sustainable arrangements will have to be negotiated to address the setting of tariffs for gas movements within Ukraine – this, of course, will also be required insofar as gas imports use a portion of the transit line system.
iii. However, if the consortium does take over the entire system, the issue of interfaces within the high pressure system will not have to be addressed, all that will need to be addressed are the interfaces between the high pressure system and the low pressure systems.
iv. Subject to the final form of the negotiated agreement, responsibility for investment in rehabilitation of the transmission systems could well become the responsibility of the operator and this could have a bearing on the outlook for rehabilitation of the domestic transmission system (i.e. the system outside the specific transit line system).
v. Transferring the management of the entire high pressure transmission network would, of course, effectively transfer a greater level of control over the domestic gas sector to the consortium than would be the case if only the transit line system were transferred.
vi. There has also been some discussion of the possibility that a consortium arrangement only be formed to construct and operate a new transit pipeline with the existing transit system remaining under the control of Naftogaz. Under such an arrangement Naftogaz would retain full control over the existing system but would also have full responsibility for financing its rehabilitation. However, of

perhaps greater concern is the fact that such an arrangement would do little to allay concerns about Ukraine behaving as a "bad transit country".

119. There are no hard and fast precedents to suggest whether Ukraine would be better served by transferring management of the entire transmission network or only the transit line system, although there is a danger that, if excluded, the domestic transmission system would not be adequately funded or managed. The ultimate resolution, therefore, should reflect a considered assessment by the government of the relative pros and cons taking into account also the impact this issue will have on the overall negotiation with the consortium.

The Form of Management Arrangement

120. In considering the specific form of the management arrangement, three models are broadly available:

Privatization

121. Outright privatization of the transit line system (or the entire high pressure transmission system) is the first of these options. A sale of the pipeline assets would have the benefit of generating an upfront payment to the budget and would not preclude ongoing revenues related to taxes or transit fees (see the further discussion on this below). A number of issues would, however, have to be addressed if the privatization approach is selected:

i. Under privatization, both the ownership of the underlying assets – the pipeline system – and the operation of these assets would be placed under private ownership. The new owner (in this case the proposed consortium) will continue to own the assets indefinitely, in other words, until the economic life of the asset is complete and the asset is abandoned[33] or disposed of, or until the asset is sold to another operating company. In effect, the State of Ukraine would relinquish its ownership control of the pipeline system.

ii. In any privatization arrangement, the issue of valuation takes on paramount importance. The full capital cost of replacing the entire high pressure transmission network is estimated to be on the order of $20 to $25 billion. The capital cost of replacing the transit line system in isolation (with a capacity of 170 BCM per year) is estimated to be on the order of $10 to $11 billion. The depreciated value of the system is, of course, substantially less than this – perhaps one third of the replacement cost.

While both replacement cost and depreciated value are indicators of interest to a seller of assets (in this case the State of Ukraine), neither of these are of relevance to an investor interested in purchasing these assets. Instead, an investor will value

[33] One factor to be considered in the privatization of an asset of this sort is the need to make provision for the appropriate disposal of the asset at the end of its economic life.

the assets at the net present value of their expected future cash flows. In other words, what will be critical to the investor is what can be earned from the operation of the pipeline system. In the case of Gazprom, this evaluation is complicated by the need to compare costs of delivering gas to European markets via Ukraine with other alternatives in order to assess the net cash flows attributable to using the Ukraine system.

Differences in the perception of the value of the transmission system (and the transit system component) between Ukraine and the non Ukrainian members of the planned consortium are likely to be a major constraint to pursuing the privatization option. This issue reportedly proved to be a sticking point when Shell made an offer in July 1997 to acquire a 50% stake in the Ukrainian pipeline system[34].

iii. Privatization of a major strategic asset such as the transit gas pipeline system is an emotive issue in Ukraine. Any proposal to privatize the system will likely encounter opposition from various sources within the country, including members of the Verkhovna Rada who may well argue that this constitutes a sale of Ukraine's "crown jewels".

A Concession Arrangement

122. The second option is a concession arrangement. Under a concession arrangement the ownership of an asset typically remains in State hands, but the right to operate the asset and the duty to maintain it are granted to a private operator. Concession arrangements are normally long term in nature – 15 years plus, and the right to operate the asset remains with the contracted operator for the term of the concession.

123. A concession arrangement in Ukraine would have the advantage of alleviating concerns about the outright sale of a key strategic asset while transferring the obligation to maintain and enhance the pipeline system to the consortium. Some up front payment may be obtainable for the concession but would likely be less than could be obtained from an outright sale.

124. If a concession arrangement were selected, care would have to be taken in the design of the concession agreement to ensure that the interests of Ukraine and of the consortium remain consistent throughout the life of the concession, by including, for example, appropriate incentives to upgrade and maintain the system as the end of the concession approaches.

A Management Contract

125. The third option is a management contract to operate the system. Under a management contract, Ukraine would enter into an agreement with the consortium to manage the operation of the transit line system for a fee. Ownership of the asset would

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[34] Source: Cambridge Energy Research Associates.

remain with the State as would the obligation for funding capital investments. The primary reason for entering into a management contract would normally be to upgrade the expertise associated with management of the system.

126. These three options are not mutually exclusive. Two or all three options could be employed sequentially. A management contract could evolve into a concession arrangement or to an outright privatization while a concession arrangement could be succeeded by full privatization after transfer of the ownership of the assets to the concession holder.

127. In selecting among the three options, Ukraine will need to consider its primary objectives for the system. If a key driving force is to secure funding for rehabilitation and expansion of the system, a management contract would not be appropriate. At that point, the choice between a concession and outright privatization would reflect both the relative political acceptability of the two options and the importance attached to securing upfront funding for the budget. If the main objective is to secure a significant near term inflow of funds to the budget, privatization is likely to be preferable to a concession (although in net present value terms a concession could deliver as much value).

Access to the Transit System

128. Broadly speaking, there are two models applicable to pipeline operations that Ukraine should consider with regard to the transit pipeline system. These are contract carriage and common carriage arrangements.

Contract Carriage Arrangements

129. Under contract carriage arrangements, the pipeline operator enters into transportation contracts with specific shippers or purchasers[35] of gas. These parties are only entitled to transport gas to the extent that they have contracted for capacity, and they pay for that contracted capacity whether or not they actually use it in full. The pipeline operator's obligations include ensuring that the contracted capacity is available to the contracting parties. The operator, however, is under no obligation to make additional capacity available over and above the contracted capacity level.

130. Tariffs for such arrangements are typically negotiated (although, under certain circumstances, the negotiations can be made subject to regulatory oversight). Such negotiations will generally take account of volume requirements, the duration of the contract and the extent to which service is interruptible at the discretion of the pipeline operator. Contract carriage arrangements will also typically include provisions to allow customers to overrun their capacity allocations when there are no detrimental impacts on the system and provisions to allow for the trading of capacity among pipeline users.

[35] It is not uncommon, under a contract carriage arrangement, for large customers to secure access to capacity and then seek gas supplies to meet their requirements.

131. A contract carriage arrangement assures the pipeline owner that it will secure an acceptable return on its investment and provides the shipper with the assurance that it will have access to transportation at a clearly defined price.

Common Carriage Arrangements

132. The concept of common carriage was initially developed in the United States in the late 19th century and was designed to encourage the provision of carriage services to the entire public at reasonable prices. In its purest form the common carriage concept is most commonly found in the telecommunications sector. As a practical matter, the pure form of common carriage is not generally applied to so called "common carriage" gas pipeline systems where shippers routinely enter into contract arrangements. For these systems, however, the "common carriage" approach does provide for broader access to a system than may be available in a dedicated contract carriage system. For example, such arrangements may stipulate that any potential shipper is entitled to access the gas transportation system under a set of clearly defined terms and conditions. In the event requests for shipment exceed available capacity, the pipeline operator may be required to pro-rate access to the capacity and could potentially be obligated to install additional capacity provided the requesting shippers are prepared to pay the cost for installing and operating this additional capacity.

133. Tariff arrangements for "common carriage" pipelines are generally subject to regulatory oversight as are other essential features relating to access to a "common carriage" pipeline.

134. Common carriage elements are frequently introduced at the behest of a government authority such as the regulator with the overarching objective of promoting market development. Such an arrangement typically has the following key goals:

i. It provides an assurance that shipping parties will be able to obtain a transportation service which is both physically and financially "firm";

ii. It provides appropriate incentives for both parties, i.e. the shipper and the pipeline owner/operator to undertake and pay for augmentation of the pipeline. For example, in return for funding pipeline augmentations, a shipping party may receive a legally enforceable right to access to pipeline capacity which it can subsequently trade if it wishes.

135. The current system in Ukraine follows the contract carriage model. Gazprom has contracted for the transportation of agreed volumes at a negotiated tariff (which is largely paid in kind – this is discussed further below). This is likely to be the model that the consortium would prefer. However, it will likely be in Ukraine's longer term interest to require the consortium to accept provisions to allow domestic gas producers (under the appropriate contract terms) access to the transit system and hence to export markets.

136. The domestic high pressure gas transmission system needs to be designed more along the lines of the "common carriage" model, in that it should provide assurances that access to markets can be made available under appropriate contract terms, if competition in the upstream portion of the gas sector is to be promoted.

137. As part of this process, it would be desirable for Ukraine to establish an Access Code for the Natural Gas Pipeline Systems. Core principles of the code would include the following items:

- Enabling shippers to negotiate access to pipeline transportation services on fair and reasonable commercial terms and conditions;
- Facilitating negotiations and addressing the imbalance in negotiating power between pipeline operators and seekers of pipeline access;
- Ensuring a transparent methodology for setting tariffs for the various pipeline transportation services;
- Ensuring consistency in the development and implementation of access regulations among all shippers;
- Providing a dispute resolution mechanism.

138. In establishing this Access Code, certain considerations should be kept in mind:

i. International agreements (including the Energy Charter Treaty) stipulate that countries should not discriminate between transit operations (i.e. in this case Russian gas) and operations involving "products originating in or destined for its own Area" (in this case Ukrainian producers and consumers).

ii. To date, Gazprom has been able to insist on restrictions related to the export by Ukraine of gas since it wants to ensure that Ukraine does not seek to benefit from purchasing and re-selling Russian gas and possibly reducing Russia's share of the European market. EU directives, however, are designed to prohibit this type of constraint and Ukraine should seek an accommodation with Russia that will allow exports of Ukrainian gas[36].

Maximizing the Economic Rent Secured by the State

139. Ukraine has been able to capitalize on its location as a gateway to Europe by securing economic rent from the transportation of Russian gas to western markets. Until recently, however, almost all of this rent was retained by the pipeline system operator, Naftogaz, and, even now, there are questions as to whether the State is receiving its fair share of the available rent. Looking to the future, the government needs to ensure that not only will the State receive its fair share of the available rent but that conditions will exist that will promote an increase in the overall level of rent available (e.g. through an

[36] Naftogaz currently has an agreement to re-export some volumes of gas this year (2003) and it is projected that re-exports will eventually total about 7.5 BCM.

increase in volumes of gas transported, and increases in the payments to the State or a combination of both).

140. Transit countries are typically able to extract economic rent for the transit of energy (gas, oil electricity etc.) through sharing in the profits associated with such transportation (when the transporting enterprise is partially or wholly State owned) and/or through tax receipts (which may be paid in the form of transit fees). The transporting enterprises cover their costs and generate profits from the tariffs charged to shippers which may be the result of negotiation or the application of regulation.

141. Since Ukraine became independent, the tariff arrangements for the transportation of Russian gas through Ukraine to European markets have largely been handled in kind – i.e. they are paid for in the form of gas delivered to Ukraine. Arrangements have involved the provision of specific volumes of gas with the deemed value of the tariff adjusting to reflect the deemed value of the gas. In 2002, it was agreed that, with gas valued at $50/MCM, the tariff would be $1.093/MCM per 100 kilometers and this applied in the first half of the year. In the second half of the year, however, gas was deemed to be valued at $65/MCM and the deemed tariff increased to $1.46/MCM per 100 kilometers. It was also agreed that 10% of the tariff would be paid in cash with the proportion of cash payments scheduled to increase over time. The net effect was that Ukraine received about 26 BCM of gas in 2002 as payment for the transport of Russian gas[37] along with some $141 million in cash. With imported gas valued at $50/MCM (the deemed price for the tariff calculation for the first half of the year), the deemed value of the tariff payment totaled about $1.5 billion.

142. The actual value realizable by Ukraine, however, is very much dependent on Naftogaz' ability to monetize the gas provided as an in kind tariff[38]. With prices in the domestic market averaging $33.68/MCM in 2002 and with payment levels of about 85%, the value actually realized by Naftogaz for the cash payment plus the 26 BCM of gas delivered as payment in kind dropped from a deemed value of $1.5 billion to a level of $900 million. In other words, Ukraine's domestic pricing policies resulted in an effective loss of transit revenue on the order of $600 million and the effective transit tariff was reduced to about $0.68/MCM per 100 kilometers.

143. This effective loss of transit revenues not only underscores the need to increase domestic gas prices to full economic value levels, it also highlights the desirability of converting the tariff payment from a largely in kind payment to a 100% cash payment. (In other segments of the system that transports gas to western markets, Gazprom does pay the full tariff in cash). The requirement for a 100% cash tariff should be a key component of the proposed new arrangements. In addition, transparency of this issue should be increased by making public both the calculation and the actual amounts of tariffs paid. This would be consistent with the "publish what you pay" initiative now

[37] Under the terms of the 10 year transit agreement that was concluded at the end of 2002 (extending to 2013) between Naftogaz and Gazprom, at least 110 BCM per year will be transported through Ukraine guaranteeing Ukraine a minimum tariff payment in kind of 26 BCM/year.
[38] The gas and cash payments were made to Naftogaz as the pipeline system operator.

being widely promoted as a means of minimizing corruption and inefficiency in activities involving oil and gas extraction and transportation.

144. Since the beginning of 2001, Naftogaz has made a payment to the State budget of $0.29/MCM per 100 kilometers for the gas transported through Ukraine[39]. With gas valued at $50/MCM, this constitutes a tax payment equivalent to 26.6% of the value of the gas[40]. As is discussed further below, there is some question as to whether this tax payment is adequate given tax or tax equivalent payments attributable to gas transit operations elsewhere.

145. Three approaches can be used by a transit country to generate tax or tax equivalent revenues associated with the transportation of energy through its territory:

i. The first is an agreement on a unit amount to be paid to the budget as a de facto transit fee. (This is, in effect, the arrangement that currently exists in Ukraine). Such a payment could be made directly by the shipper or it could be routed through the transportation company.

ii. The second is to address the issue through the transportation company's normal tax payments. However, in the case of Ukraine, Naftogaz' failure to meet its full tax obligations calls into question the viability of such an approach.

iii. The third is for the State to be the recipient of the full tariff payments, with the State then paying the transportation company for the transportation of the gas in accordance with a regulated cost plus tariff. Such an arrangement works well when tariffs are paid in cash. However, with in kind tariffs, the need to monetize the gas complicates the arrangement and makes it substantially less attractive.

146. In structuring the consortium arrangement, the government will need to determine which option will likely deliver the optimum results in terms of maximizing revenue to the State budget and maximizing transparency. Experience elsewhere suggests that Ukraine may be best served by focusing on the first option – i.e. payment of a transit fee directly to the State budget in lieu of all income taxes. Such an arrangement, which lends itself to a high degree of transparency, will be easy to monitor and limits the government to one financial negotiation issue – the level of transit payments. The issue of overall tariff levels for the transit of Russian gas then becomes one of negotiation between the shippers and the consortium operating the pipeline.

147. International trade agreements (e.g. GATT and WTO) stipulate that tariff arrangements for the transit of energy should be based on cost. It is, however, widely accepted that such cost should include tax payments to the host state which can take the form of standard taxation arrangements in accordance with the state's tax code, or can take the form of specific transit fees. This then raises the question of what would be the

[39] This payment arrangement was established in 1999 but no payments were made in 2000.
[40] With gas valued at $65/MCM the percentage drops to 19.9%.

appropriate or "correct" level of transit fee (or proxy tax payment) for the transportation of gas across Ukraine.

148. As long as transit arrangements are managed by a State owned enterprise (at the present time Naftogaz), it can be argued that it is not overly important to ensure that the amount paid to the State budget is "correct" since the State should also ultimately be the beneficiary of profits generated by the enterprise (or conversely be obliged to deal with any losses incurred by the enterprise). However, once third parties are brought into the equation in the form of equity stakeholders or concession holders in the transit pipeline, the issue of the "correctness" of the transit fees to the State assumes a much greater significance. Negotiation of this issue will be a critical element in ensuring that Ukraine secures its fair share of the economic rent associated with the transportation of gas across its territory.

149. The starting point for such a negotiation will likely be the $0.29/MCM per 100 kilometers that has been agreed as the payment by Naftogaz to the State budget. In many cases it is difficult to disaggregate the specific taxes attributable to energy transit operations. However, there are some cases where standalone fees (i.e. fees that are independent of tariff levels and payments) have been negotiated for the transit of gas and these provide comparative benchmarks for Ukraine to consider. These cases do offer precedents for a higher unit transit fee (or proxy tax payment) than the $0.29/MCM per 100 kilometers that the State budget currently receives.

150. Two different approaches can be used for setting and comparing transit fees. The first is a distance related basis in which the fee is adjusted on a per hundred kilometer rate. The second is a fixed per country basis in which an absolute amount is set irrespective of the distance traversed. There are very few standalone transit fee arrangements for gas (i.e. fees that are independent of tariff levels and payments). Table 19 summarizes three cases which are good international comparators and compares them with the fiscal revenues currently being secured by the State budget in Ukraine.

Table 20
Gas Transit Fee Arrangements

Transit Country	Source of Gas	Approx. Distance km	Transit Fee	
			$/MCM	$/MCM/100 km
Tunisia	Algeria	370	~5.00	1.35
Morocco	Algeria	450	7.00	1.56
Georgia[41]	Azerbaijan	250	2.50	1.00
Ukraine	Russia	1,100	3.19	0.29

151. As Table 20 indicates, using either a distance based approach or a fixed country based approach, the Ukraine State budget is currently extracting less economic rent in the form of deemed transit fees for gas than either Tunisia or Morocco and is also extracting

[41] This is the proposed Shah Deniz gas transit arrangement. Under this arrangement the transit fee in the first year will be $2.50/MCM. This rate will then escalate at 2% per year.

substantially less in distance terms than will Georgia under the proposed Shah Deniz gas transit arrangement.

152. Under the current arrangement, the value of the tariff fees paid to Naftogaz for the transit of Russian gas is directly related to the value placed on the Russian gas. The values placed on Russian gas deliveries into Ukraine are currently well below parity with prices paid for Russian gas in the European market. Over time, however, it is likely that Russian gas prices into Ukraine will evolve towards parity with European prices increasing the value of the tariff fees paid in kind (see the next sesction of the report for further discussion on this issue). If the State budget is also to benefit from these value increases, the budget take (i.e. the deemed transit fee) would need to be linked to the tariff fee payment, for example in the form of a percentage of the deemed tariff.

153. In summary, therefore, the State's interests will best be served by seeking a higher fiscal take (or deemed transit fee) with some form of escalator provision that is consistent with whatever escalator provision applies to the overall tariff for gas transit. In addition, the State needs to ensure that it receives its payments in the form of cash and information about these payments should be made publicly available. Such payments would constitute fulfillment of the tax obligation associated with the consortium's operation of the pipeline.

154. As has been noted, under the new consortium arrangement, the consortium could negotiate independently the tariff arrangement for the transit of gas from Russia and/or from Central Asia to western markets. However, tariffs also need to be set for gas deliveries into Ukraine, for intra-Ukraine movements and for gas exports from Ukraine. These tariffs should not be subject to independent negotiation but, rather, should be established by the regulator (NERC) in accordance with an appropriate published methodology. In order to simplify tax collections, the tax payments attributable to such movements should also be made in the form of a unit amount to be paid as a transportation fee.

155. Under a cost plus calculation methodology, the total transportation tariffs need to cover not only operating and maintenance costs but also need to provide sufficient revenues to cover required capital investments in the system and provide a rate of return on the overall operation of the system. This is likely to require a tariff level on the order of $0.80 to $1.00/MCM per 100 kilometers. However, a full assessment is going to have to be made by NERC to ascertain exactly what tariff level is required to cover costs and provide an appropriate return on investment.

Conclusions and Recommendations

156. The transit gas pipeline is a major strategic asset that not only provides significant transit fee revenue but also offers the opportunity for a substantial increase in both transit volumes and transit revenues. If this opportunity is to be fully realized, however, Ukraine needs first to convince Russia that it will act as a "good transit country" for the indefinite future and second to ensure that a transit fee arrangement is put in place that

ensures that the State budget will receive its fair share of the economic rent associated with the transit arrangements.

157. The proposed arrangement whereby a consortium with representation from Ukraine (initially in the form of Naftogaz), Russia (in the form of Gazprom) and possibly western interests would take over the operation of the pipeline will go a long way to assuage Russian concerns about how Ukraine will perform as a transit country. This arrangement also has the potential to provide the capital investment funds needed to rehabilitate the transit pipeline system and subsequently expand it.

158. With or without a new arrangement for the management and operation of the transit pipeline system, the transit tariff needs to be reviewed and, more particularly, the amount allocated to the State budget as its share of the economic rent from the operation of the pipeline needs to be re-examined. Payment of tariffs should be converted from a predominantly in kind arrangement to a 100% cash arrangement and information on the arrangements should be made publicly available.

159. The transit pipeline system also represents a potential export outlet for domestic gas production. Access to export markets will greatly enhance the attractiveness to prospective investors of the upstream gas sector. Such access can be provided by requiring that the pipeline system reserve some capacity for domestic production and by providing for NERC to establish tariffs for such operation together with tariffs for imports and intra-Ukraine transportation.

160. The Bank, therefore, has the following recommendations:

i. Ukraine should continue with plans to establish a consortium arrangement (with Gazprom participation) to take over the operation of the pipeline. While Ukraine needs to consider the options of privatization, a concession arrangement and a management contract, it is the Bank's view that a concession arrangement is likely to offer the best prospects for reaching a satisfactory agreement. The government also needs to designate an agency to be accountable for the negotiation of these arrangements. Since Naftogaz will be a part of the consortium, it would be preferable to limit the Naftogaz involvement to one of providing technical assistance. The State Property Fund is the owner of the pipeline assets and would, therefore, be a logical choice as the accountable agency.

ii. Negotiations to set up the consortium need to provide for:

- Payment of a transit fee (in lieu of all other income taxes) to the State budget. This payment should be made in cash.
- Coverage of financing needs for both rehabilitation and expansion of the capacity of the line.

- Access to the system for other users. Other potential users include domestic producers seeking to export gas as well as other producers interested in gas transit (e.g. Central Asian producers).
- Public disclosure of the negotiated arrangement.

iii. NERC should undertake and keep up to date a comprehensive assessment of the cost of the line taking into account future capital investment requirements and a return on investment factor.

iv. With the assistance of NERC, the Government should make an assessment of the equitable level of economic rent that should be secured for the State through the State budget and should negotiate initially with Naftogaz and, subsequently with the consortium (see item ii above), to secure this level of transit fees. Revised terms could be implemented as early as 2004.

v. To the extent that transit tariffs are linked to gas values, the Government should ensure that the State budget will benefit from any increase in gas values.

vi. Payment in kind arrangements suffer from a lack of transparency. Consequently, pending negotiation of a consortium arrangement, the Government should seek to replace the existing payment in kind approach with cash payments for the full transit tariff.

Increasing Competition in the Domestic Gas Market

161. In May 1998, a joint World Bank-government working group on gas reform reached agreement on an action plan that included the following steps to be taken during 1998-2001:

- Setting up in 1998 of a state-owned joint stock company to operate the transmission network, and appointment in 1999 of a consortium of domestic and foreign companies to manage the shares of this company for at least 15 years. State ownership in the consortium would be limited to 25 percent plus one share. The allocation of transmission capacity would be market based, ensuring equal treatment of all domestic shippers.

- Introduction in 1999 of incentives and criteria to improve the collection performance of gas distribution companies.

- Starting in mid-1998, organization of quarterly gas auctions where gas traders and large consumers can purchase gas from Ukragazprom for cash.

- Separation and privatization of the gas production activities of Ukragazprom and the gas exploration activities of the State Geology Committee.

162. The objectives of the action plan were to improve the financial performance of the sector and to create a competitive market environment. However, the only one of these action items that was effectively implemented was the creation of appropriate incentives to improve collections. This has brought cash collections up to a level of about 89%. Discussions have been underway on the formation of a consortium to manage the transit line but nothing has yet been implemented. Gas auctions were introduced but failed to operate effectively in the face of a non transparent pricing structure and moves on the part of Naftogaz towards the single buyer model. This latter effort has also led to the demise of independent gas traders. While there is some limited private sector involvement in upstream gas activities there has been no action taken with regard to the separation and privatization of the gas production activities controlled by Naftogaz.

163. With hindsight it appears that the action plan failed, in large part, because it conflicted with the expectations associated with the establishment of Naftogaz as a vertically integrated State owned company managing all the State owned assets in the oil and gas sectors. The failure of the 1998 action plan, however, does not preclude the prospect of Ukraine establishing a competitive domestic gas market in the future.

164. The European Union Gas Directives[42] are designed to promote an increased level of competition within the internal EU market and the directives do provide a template that Ukraine should consider for its gas sector. The transition to a fully competitive

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[42] Directives 98/30/EC and 03/55/EC

market could be handled in a phased fashion as part of a broader reform effort. The phased process outlined in Box 7 below addresses the issue of increased competition and also incorporates recommendations contained in the earlier portions of this report.

Box 7
A Reform Program for the Ukrainian Gas Sector

Phase	**Supply**	**Transmission/Storage**	**Distribution**
At Present	Naftogaz dominates domestic production with an interest in over 95% of gas production. Naftogaz is the recipient of all transit fee gas (26 BCM in 2002) Naftogaz receives all gas imported under a government to government deal.	Naftogaz has the exclusive right to operate the gas transmission assets which are owned by the State Property Fund. Naftogaz owns and manages all the gas storage in Ukraine.	Naftogaz is a major shareholder in most of the 46 gas distribution companies. Naftogaz is expected to re-export about 7.5 BCM of purchased gas in 2003.
Phase 1	Liberalize well-head prices and strengthen the environment for upstream investments. Establish the producing enterprises as autonomous corporate entities with separate management, separate accounts and separate accountability. Replace the in-kind transit fee with a cash transit fee and purchase the gas currently being supplied as a transit fee in kind.	Establish non discriminatory terms and conditions for access to the trunk transmission system (including the transit line) Establish the proposed consortium to manage the transit pipeline and transfer management responsibility. Establish open access policies to the gas storage facilities and undertake pre-privatization analysis.	Undertake pre-privatization work for the distribution companies. This should include consideration of a consolidation of the companies.
Phase 2	Replace the single buyer model with bi-lateral contract arrangements and/or a wholesale market arrangement. Offer the producing enterprises for privatization.	Offer the gas storage facilities for private management (possibly under a concession arrangement). Transfer any residual transmission activities to private sector management.	Offer the distribution companies for privatization.

165. On the supply side, the key change proposed is replacement of the single buyer model with bi-lateral contract arrangements and/or a wholesale market arrangement. At

present, Ukraine relies on Gazprom and on Turkmenistan for its gas import requirements. In the future, however, this may well change. The Russian gas sector is evolving and there is the prospect that non Gazprom supplies will increase and may be available to the Ukrainian market. Consequently, as Ukraine converts its transit fee arrangements from payment in kind to payment in cash it may have some supplier options as it establishes arrangements to purchase gas to replace the payment in kind volumes. This opens up the possibility that Ukraine will be able to benefit from some level of gas to gas competition among its potential suppliers.

166. Ukraine's current contract with Turkmenistan continues through 2006 and negotiations are underway for a 25 year contract to follow this. There are, however, some serious questions about Turkmenistan's ability to deliver all its potential commitments. Without an aggressive investment program Turkmenistan's production capacity will likely remain below its historic peak of about 84 BCM[43]. Turkmenistan currently has contracts to supply both Iran and Ukraine and has entered into an agreement to start supplying Russia with significant volumes of gas in 2007[44]. Table 21 summarizes the supply/demand outlook for Turkmenistan gas in 2010 under both a moderate investment and a low investment scenario assuming an extension of the existing contract to supply Ukraine and of deliveries to Iran.

Table 21
Turkmenistan Gas Supply Outlook
in 2010

	BCM
Gas Available for Export:	
Moderate Investment Scenario	63
Low Investment Scenario	42
Export Demand:	
Iran	8
Ukraine	36
Russia	73
Total	117
Shortfall :	
Moderate Investment Scenario	(54)
Low Investment Scenario	(75)

Source: Industry sources

167. This strongly suggests there will not be sufficient supply from Turkmenistan to meet the demands of both Russia and Ukraine. Competition between Russia and Ukraine

[43] Turkmenistan claims that it will increase production to 120 BCM by 2010. However, since this would likely require capital investments on the order of $7 to $10 billion such a production level is unlikely to be achieved.
[44] The 25 year agreement between Russia and Turkmenistan calls for Turkmenistan to supply 6 BCM in 2004, 6 to 7 BCM in 2005, up to 10 BCM in 2006 and 60 to 70 BCM in 2007 with deliveries subsequently rising to as much as 80 BCM.

for Turkmenistan gas supplies could well have price ramifications for Ukraine's gas supplies.

168. At present the effective cost of gas imports to Ukraine ($50/MCM) is less than half the European parity price. The netback price to the Russian border for sales to Western Europe in 2003 is estimated as $108/MCM[45]. This price, of course also reflects the current high oil price environment. However, if prices were to drop to $22 per barrel (the bottom of the OPEC target band) the netback price to the Russian border would still be on the order of $85/MCM. It is, therefore, likely that as supplies tighten, upward pressure will be exerted on prices of gas for delivery to Ukraine. Faced with such an outlook the role of competition in moderating price increases in respect both of imports and sales to the ultimate consumers in Ukraine will become increasingly important.

[45] Source: United Financial Group.

Appendix 1

Ukraine Gas Sector Implicit Subsidies for CY 2001

GDP, UAH billion	204.2

Consumers	Consumption mm CM	Billings UAH 000s	Avg. Tariff UAH 000s	Collections UAH 000s	% of Billings	Current Billings-Collections UAH 000s	Current Billings-Collections US $ 000s	Avg. Tariff US $/MCM	Avg. Value US $/MCM	Transm. US $/MCM	Distr. US $/MCM	Tot. Value US $ 000s	Collections US $ 000s	Subsidies US $ 000s
Households														
Direct Sales	15,426	962,457		837,338	87%	125,119	23,300							
Privileges		384,590		388,436	101%	(3,846)	(716)							
Subsidies		504,073		529,277	105%	(25,204)	(4,693)							
Sub Total	15,426	1,851,120	120	1,755,050	95%	96,070	17,890	$ 22.35	$ 50.00	$ 1.50	$ 3.90	$ 854,600	$ 272,354	$ 582,246
Budget Enterprises														
Local Budget	396	67,320	170	60,588	90%	6,732	1,254	$ 31.66	$ 50.00	$ 1.50	$ 3.90	$ 21,938	$ 9,402	$ 12,536
State Budget	515	87,550	170	77,920	89%	9,631	1,793	$ 31.66	$ 50.00	$ 1.50	$ 3.90	$ 28,531	$ 12,092	$ 16,439
Sub Total	911	154,870	170	138,508	89%	16,363	3,047	$ 31.66	$ 50.00	$ 1.50	$ 3.90	$ 50,469	$ 21,494	$ 28,975
CHP & Industrial Boilers	9,258	1,666,440	180	1,399,810	84%	266,630	49,652	$ 33.52	$ 50.00	$ 1.50	$ 3.90	$ 512,893	$ 217,227	$ 295,666
State Budget Communal	134	44,220	330	47,758	108%	(3,538)	(659)	$ 61.45	$ 50.00	$ 1.50	$ 3.90	$ 7,424	$ 7,411	$ 12
Industry														
Chemical	1,639	536,465	327	509,714	95%	26,751	4,982	$ 60.95	$ 50.00	$ 1.50	$ 1.95	$ 87,605	$ 79,099	$ 8,506
Metallurgy	2,676	858,274	321	786,692	92%	71,582	13,330	$ 59.73	$ 50.00	$ 1.50	$ 1.95	$ 143,032	$ 122,081	$ 20,951
Machinery	12	4,143	345	4,263	103%	(120)	(22)	$ 64.29	$ 50.00	$ 1.50	$ 1.95	$ 641	$ 662	$ (20)
Agriculture	54	17,925	332	12,731	71%	5,194	967	$ 61.81	$ 50.00	$ 1.50	$ 1.95	$ 2,886	$ 1,976	$ 911
Energy Complex	6	1,851	309	1,936	105%	(85)	(16)	$ 57.45	$ 50.00	$ 1.50	$ 1.95	$ 321	$ 300	$ 20
Other	632	208,653	330	207,930	100%	723	135	$ 61.48	$ 50.00	$ 1.50	$ 1.95	$ 33,780	$ 32,267	$ 1,513
Sub Total	5,019	1,627,311	324	1,523,266	94%	104,045	19,375	$ 60.38	$ 50.00	$ 1.50	$ 1.95	$ 268,266	$ 236,385	$ 31,880
Gencos	4,465	1,480,285	332	1,134,486	77%	345,799	64,395	$ 61.74	$ 50.00	$ 1.50	$ 1.95	$ 238,654	$ 176,053	$ 62,601
JSC Kievenergo	3,188	605,541	190	558,126	92%	47,415	8,830	$ 35.37	$ 50.00	$ 1.50	$ 1.95	$ 170,399	$ 86,612	$ 83,787
Other Consumers	3,747	1,216,688	325	1,216,688	100%			$ 60.47	$ 50.00	$ 1.50	$ 1.95	$ 200,277	$ 188,809	$ 11,468
Total	42,148	8,646,475		7,773,691	90%	**872,784**	**162,530**							
Total (without VAT)						**727,320**	**135,441**					$ 2,302,982	$ 1,206,346	**$ 1,096,637**
% of GDP						**0.36%**	**0.36%**							**2.88%**

Ukraine Gas Sector Implicit Subsidies for CY 2002

GDP, UAH billion 220.9

Consumers	Consumption mmCM	Billings UAH 000s	Avg. Tariff UAH 000s	Collections UAH 000s	% of Billings	Current Billings-Collections UAH 000s	Current Billings-Collections US$ 000s	Avg. Tariff US$/MCM	Avg. Value US$/MCM	Transm US$/MCM	Distr. US$/MCM	Tot. Value US$ 000s	Collections US$ 000s	Subsidies US$ 000s
Households														
Direct Sales	15,492	1,078,274		1,035,143	96%	43,131	8,092							
Privileges		351,704		365,772	104%	(14,068)	(2,639)							
Subsidies		429,062		407,609	95%	21,453	4,025							
Sub Total	15,492	1,859,040	120	1,808,524	97%	50,516	9,478	$ 22.51	$ 50.00	$ 1.50	$ 3.40	$ 850,511	$ 282,759	$ 567,752
Budget Enterprises														
Local Budget	433	73,610	170	70,666	96%	2,944	552	$ 31.89	$ 50.00	$ 1.50	$ 3.40	$ 23,772	$ 11,048	$ 12,723
State Budget	489	83,130	170	79,805	96%	3,325	624	$ 31.89	$ 50.00	$ 1.50	$ 3.40	$ 26,846	$ 12,477	$ 14,369
Sub Total	922	156,740	170	150,470	96%	6,270	1,176	$ 31.89	$ 50.00	$ 1.50	$ 3.40	$ 50,618	$ 23,526	$ 27,092
CHP & Industrial Boilers	9,421	1,695,780	180	1,322,708	78%	373,072	69,995	$ 33.77	$ 50.00	$ 1.50	$ 3.40	$ 517,213	$ 206,802	$ 310,410
State Budget Communal	112	36,960	330	38,069	103%	(1,109)	(208)	$ 61.91	$ 50.00	$ 1.50	$ 3.40	$ 6,149	$ 5,952	$ 197
Industry														
Chemical	2,082	677,304	325	677,804	100%	(500)	(94)	$ 61.03	$ 50.00	$ 1.50	$ 1.70	$ 110,762	$ 105,973	$ 4,789
Metallurgy	4,154	1,347,257	324	1,231,958	91%	115,299	21,632	$ 60.85	$ 50.00	$ 1.50	$ 1.70	$ 220,993	$ 192,614	$ 28,379
Machinery	6	1,896	333	1,991	105%	(95)	(18)	$ 62.41	$ 50.00	$ 1.50	$ 1.70	$ 303	$ 311	$ (8)
Agriculture	13	4,350	335	5,406	124%	(1,056)	(198)	$ 62.78	$ 50.00	$ 1.50	$ 1.70	$ 692	$ 845	$ (154)
Energy Complex	0.3	100	333	70	70%	30	6	$ 62.54	$ 50.00	$ 1.50	$ 1.70	$ 16	$ 11	$ 5
Other	981	321,276	327	271,081	84%	50,195	9,417	$ 61.44	$ 50.00	$ 1.50	$ 1.70	$ 52,189	$ 42,383	$ 9,806
Sub Total	7,236	2,352,183	325	2,188,310	93%	163,873	30,745	$ 60.99	$ 50.00	$ 1.50	$ 1.70	$ 384,955	$ 342,137	$ 42,818
Gencos	4,077	1,351,671	332	1,256,516	93%	95,155	17,853	$ 62.20	$ 50.00	$ 1.50	$ 1.70	$ 216,896	$ 196,453	$ 20,443
JSC Kievenergo	3,358	691,838	206	569,123	82%	122,715	23,023	$ 38.65	$ 50.00	$ 1.50	$ 1.70	$ 178,646	$ 88,981	$ 89,665
Other Consumers	1,655	539,321	326	539,321	100%	1,031,150	193,462	$ 61.14	$ 50.00	$ 1.50	$ 1.70	$ 88,046	$ 84,322	$ 3,724
Total	42,273	8,683,533		7,873,042	91%	810,491	152,062							
Total (without VAT)						**675,409**	**126,718**					2,293,034	1,230,932	**$ 1,062,101**
% of GDP						**0.31%**	**0.30%**							**2.55%**

Appendix 2

The Regulator[1]

1. This appendix lists the key functions needed by the regulator to further the development of competition in the market. It examines the liberalization process and regulatory models adopted in the UK, USA, California, Romania and Germany and explains how they have promoted or hindered competition and the functioning of the market.

Key Features of Regulatory Function to Promote Competition

2. The regulator has to have powers to encourage competition and prevent anti-monopoly behavior. If these powers are backed up by a strong national law on competition and the prevention of monopoly abuse of power, the regulator does not need additional strong legal powers. However if this law is weak, strong laws and powers need to be provided expressly for the gas industry (and the remainder of the energy industries). Specifically, the regulator needs to able to police and punish anti-competitive behavior. The first step is to provide some basic principles:

- ***Separate Natural Monopoly Activities from all other activities***
    - This does not necessitate full legal separation, but if full legal separation does not exist, there needs to be strong institutional separation including a compliance team appointed by the regulator and reporting to the regulator and third parties to whistle blow abuses, and with full powers to investigate complaints.
    - There also needs to be full and accurate published accounts on all the activities of the monopoly services allocated in fine detail to cover all the activities of the company.
    - Non-Discrimination provision. Third parties need protection, backed up by regulatory powers, to police and punish any discrimination exhibited by the monopolist.

- ***Separate monopoly activities from all other activities***
    - The same issues apply as for a natural monopoly, but these activities should be presumed to be open to competition over time, preferably to a defined timetable.
    - The power of separation is difficult to exaggerate – effectively done it provides confidence to the industry that it will be treated fairly.

- ***Full legal separation is the best option***
    - With full legal separation competitors know that the monopoly does not gain from treating any one company differently from any other company.
    - As long as the company is one legal entity there is advantage for it to discriminate in favor of its other parts. The only way to provide confidence is

[1] This appendix was prepared for the World Bank by Gas Strategies Consulting Ltd.

to ensure the regulator has enough powers to investigate, police, and enforce with punitive damages.
    - The first choice is therefore full separation. This can be done in two stages, starting with separation within the company and extensive powers for the regulator, followed by full demerger of shareholder interests. Many of the provisions to protect third parties can be dismantled once full separation is achieved – and this is one of the reasons companies may decide to demerge of their own accord (e.g. British Gas in the UK)

- ***Monopolies act as Monopolists***
    - Uncontrolled monopoly behavior results in too high prices, too little investment, and moribund managerial and worker behavior. A regulator is required to provide the same kind of impetus that in other industries is provided by competition.
    - The regulator needs to set overall price controls to ensure that too much money is not raised from customers and to provide incentives for productivity improvements and appropriate investment
    - Having set the overall level of prices / revenues, the regulator needs to have a clear strategy for ensuring prices are fair between consumers. This can be done in a number of ways, and would normally be a result of extensive consultation with the industry, consumers and other interested organizations. Access to good quality information is essential.

- ***Investment***
    - Third parties need to be able to request access to any service they need to provide gas to their customers. The regulator has to have powers to ensure that this access will be provided within a reasonable time frame and at a reasonable cost. Only when there is competition in potential provision of a service can this requirement for reasonable access be dropped.

- ***Information***
    - The regulator needs access to any information requested in a reasonable time frame. Ideally the regulator should have full access to all the internal accounts systems, staff, IT systems, etc to ensure that information is provided and is accurate. Where there is no information internally the regulator needs to be able to insist it is provided.

- ***Political Independence***
    - The best systems work by government providing the policy framework, and taking the tax and spend decisions, while the regulator implements the policy and works out how most effectively to deliver that policy, and works closely with government to provide the analytical framework and data to help the government make better decisions.
    - Independent regulation ensures that key regulatory decisions are not distorted by political drivers, and provides third parties with confidence that they will be treated without political bias.

- ***Powers to investigate and remedy transgressions***
    - The regulator needs full powers to investigate any complaints, abuse, and to investigate potential changes to the industry structure. It needs enough powers to dissuade the company from misbehaving in the first place, and a system of penalties if misbehavior is identified.

Regulatory Models in Developed and Transition Economies

UK

3. The UK was the first country to introduce gas market liberalization all the way to the retail customer. Gas market liberalization was promoted as part of a political and economic agenda intended to introduce competition into the downstream gas business. Competition would promote choice for customers, increased efficiency of operations, and price reductions for consumers. The process has largely been successful, and there are now 93 licensed gas-marketing companies, and prices paid by end users are among the lowest in Europe, all customers can choice their supplier, and barriers to switching are small.

4. The process of liberalization took 16 years to complete, beginning in 1982 and finishing in 1998. The process can be defined in four phases, as shown below:

Table 1: Phases of UK Gas Market Deregulation

	Measures	Effects
1982-1988	From 1982, companies other than British Gas Corporation has the right to use the existing pipeline network and supply customers with an annual consumption over 25,000 therms (732.7 MWh)	By 1985, no new suppliers had entered the market, mainly for two reasons: difficulty in accessing the transmission and distribution grid which was through negotiation with British Gas and difficulty in obtaining supplies
1988-1994	In 1988 British Gas was made to publish a price schedule and stick to it, giving new suppliers a target price to beat. British Gas was allowed to buy only 90% of new gas production In 1992 British Gas was forced to release some gas purchased under long term contracts Eligibility threshold to choose supplier 2.500 therms (73.3 MWh) – effectively all industrial customers	First third party transportation deal signed in 1990. By the end of 1990, British Gas had lost 10% of its market share. By 1995, British Gas' share of the eligible market had fallen to 50% and over 65% of industrial customers had switched suppliers

	Measures	Effects
1994-1996	Prices fell due to new entrants securing supplies. British Gas starts renegotiating long term contracts which are at higher prices British Gas share of eligible market limited to 55% The Network Code introduced setting out rules for regulated third party access to the transmission network British Gas to de-merge into Centrica (trading) and BG (transportation, exploration and international)	
1996-1998	Opening of residential market started in 1996 and was complete by June 1998	

Source: Gas Strategies

5. In the initial phase of liberalization between 1982 and 1988 there was very little material progress made toward the introduction of competition despite the legislative and regulatory changes introduced. Although the Oil and Gas Enterprise Act 1982 granted firms other than British Gas Corporation the right to use the existing pipeline network and to supply customers whose annual consumption exceeded 25,000 therms (732.7 MWh), by 1985, three years after the act, no alternate supplier had entered the market. There were a number of reasons that explain the failure of competition in the early days of liberalization. Chief among which were first, the difficulty any potential new suppliers had accessing the transmission and distribution grid which was through negotiation with British Gas and secondly, the difficulty of actually obtaining gas supplies.

6. However, with the introduction of measures to create a more competitive environment in the early 1990s, large numbers of marketers began to enter the market. The release gas programs introduced in 1992, the relatively undemanding financial credentials required for new marketers and the fact that British Gas was forced to stick to its published price schedules meant that it was relatively easy for companies to enter the market and sell gas at a profit. Furthermore, in 1992 Ofgas lowered the eligibility threshold for consumers from 25,000 therms per annum (732.7 MWh) to 2,500 therms per annum (73.3 MWh) which effectively made all but commercial and residential customers eligible to buy from suppliers other than British Gas. At the same time Ofgas put an upper limit of British Gas's allowed share of the eligible market of 55% effectively forcing them to release market share to new entrants.

7. In 1996 the network code setting out the rules and allowing for regulated third party access to the UK transmission network was established and then in 1997 British Gas de-merged into two companies, one a trading business to be named Centrica and the

second a transportation, exploration and international business to be named BG plc. Both these moves were regarded as essential by the regulator to ensure the continued development of competition. It was believed that without formal separation of the transmission and supply business and a clear transparent third party access regime competition would certainly be hindered.

8. The final phase of the process was the gradual opening of the residential market to competition. This market was opened in stages from 1996 with competition gradually introduced over a period of two years in a series of trial areas; by June 1998 this process was completed.

USA

9. The US gas industry started to be transformed to its current shape with FERC Order 436 in 1985 which encourage pipeline companies to separate their sales and transportation functions. Prior to FERC order 436, pipeline companies bought gas from producers, transported it through their pipelines, and sold it to distribution companies which then sold it to end users. A series of FERC orders, starting with 436 and culminating in FERC order 636 in 1992, unbundled these services, so pipeline companies provided services for third parties and did not own the gas they transported. Purchasers of natural gas are now able to negotiate with many different suppliers and contract separately with pipeline companies for transportation and storage. This has led to the emergence of independent gas marketers, which arrange transportation and market gas for producers. The availability of information about commodity and transportation prices via commodity markets and electronic bulletin boards mean that price signals are quickly transmitted between consumers and producers.

10. Between 1988 and 1994, the market changed considerably.

- Gas production increased by 10%, wellhead prices declined by 11% and reserves declined by 2%.
- Gas delivered to consumers increased by 16%.
- Prices to consumers dropped significantly as consumers benefited from lower wellhead prices and transportation costs.

Table 2: US Gas Market Development

1938	The National Gas Act created the Federal Power Commission (FPC) to regulate natural gas pipelines but not wellhead prices. Demand growth in the 1940s and 1950s outpaced pipeline expansion, leading to price volatility and supply shortages. Producers wanted price caps, but the FPC said it did not have the authority to introduce them.

1954	The Supreme Court decides that the National Gas Act should provide for the regulation of both pipelines and wellhead prices. This led to an industry structure where regulated gas producers sold to regulated pipeline companies, who sold gas to local distribution companies, who then sold the gas to end users. Local distribution companies were regulated by state or local agencies. This reduced price volatility but caused supply shortages, as it did not provide any incentive for producers to replace reserves.
1978	The Natural Gas Policy acted created the Federal Energy Regulatory Commission (FERC) to replace the FPC. Wellhead prices were deregulated and production increased rapidly. This led to a gas surplus. However, as pipeline companies charged enough to cover the cost they paid to purchase gas, there was no incentive for them to select the most competitively priced gas.
1985	FERC Order 436 required pipelines to provide open access, allowing consumers to negotiate prices directly with producers and contract separately with pipelines for transportation.
1987	FERC order 500 clarified some open access issues remaining after Order 436 and created a mechanism for pipeline companies to recover from their customers the costs of modifying or terminating their long term take or pay contracts with producers.
1992	FERC Order 636 required pipeline companies to provide open access transportation and storage and to separate sales completely from transportation.
1994	FERC retained the right to disregard the separate corporate structures of a pipeline company and its affiliates in the event that they abuse their interrelationship.

Source: Gas Strategies

Californian Energy Crisis

Introduction

11. The California Energy Crisis hit California in summer 2000 and ran on for the first quarter of 2001. The whole state was affected with rotating black outs and frequent brown outs hitting homes and businesses across the state. The crisis has cost the state billions both directly as a result of electricity purchases that it has had to make and indirectly in terms of damage to businesses. The crisis has led to a worldwide reappraisal of the way in which energy markets are liberalized and has caused many to call into question the wisdom of breaking up the old monopoly systems. Much of the response and lasting impression both locally and internationally is based on myth and emotion but it is a very forceful impression. Thus, whilst it is important to try to understand the real facts, it is equally important to note that most people identify the cause as “deregulation” and the liberalization agenda worldwide has been impacted by the various perceptions of California. The causes that lay behind the crisis can be summarized as:

- Fundamental electricity supply demand imbalance (supply shortage)
- Flawed electricity market structure
- Regulatory uncertainty, political interference

- Unexpectedly hot weather in summer of 2000
- Coincidence of high gas prices which further pushed up electricity prices

Legislation and Regulation

12. Although it was the fundamental supply situation which lay at the heart of the crisis the problem was exacerbated by the legislative and regulatory framework that was in place. An ever increasing spread of responsibility amongst too many regulatory and supervisory bodies, the inadequate structure of those bodies and a degree of political interference (primarily from the legislature) caused regulatory uncertainty at best, chaos at worst.

13. The supervisory bodies that were set up to oversee the CalPX (California Power Exchange) and the Independent System Operator (ISO) were too unwieldy and poorly structured to make decisions. For example, the ISO board had 28 members representing different interest groups who made decision-making practically impossible and it was one of many bodies involved. These inadequacies became particularly apparent as the crisis unfolded and quick decisions were needed. Political interference in the design of the market structure and failure to implement timely remedies made things worse not better. The frequent insistence of politicians on setting consumer prices to meet political rather than economic ends seems to have fuelled the crisis.

Pricing Systems and Market Structures

14. In 1996, the state law AB 1890 changed the structure of California's electricity industry which was intended to create a market based system from a tightly regulated monopoly system. It relied exclusively on spot, day ahead price and supply. For the first two years of the transition, market prices tracked expectations with wholesale electricity prices averaging $33 per MWh which was very close to the marginal cost of power production. However, from the summer of 2000 and through early 2001 market trends were extremely volatile with the market producing a series of problems; including very high electricity prices, decreased system reliability, very high profits for generators and wholesale power sellers and large debts for utility distributors who were forced to buy their power at inflated prices but unable to pass any of this price increase on to their retail consumers.

15. There were a number of reasons that explain the problems outlined above. Firstly the politicians were initially unwilling to allow consumers to face any price increases regardless of the cost of power, which in turn, undermined a proper demand response to higher prices, eroded supplier confidence and thus fuelled the crisis. This was manifest in the fact that retail prices were capped while the wholesale price was governed entirely by the daily spot market. In order for liberalization to work successfully, wholesale markets need a realistic contracted revenue from the retail market or a free retail market. However, politicians are often very unwilling to leave control of retail energy prices to the market. As the problems unfolded in California and the crisis deepened the governor's office categorically refused to put up retail electricity prices when only minor action was required. It was argued that a simple 2% rise in retail prices early on in the crisis could have significantly reduced its impact.

16. In addition, the decision to force all electricity sales through the CalPX (California Power Exchange) and the refusal to allow long term bilateral contracts between power producers and consumers meant that the system was structurally unstable and extremely vulnerable to massive short term price hikes. This problem was exacerbated by the fact that no realistic hedging in the forward markets was allowed (the rules were set so tight as to make permissible hedging useless). Furthermore, California did not develop a capacity market or other mechanism, which would trigger the building of generating capacity and transmission, an extremely dangerous omission, given the supply shortage that has already been described. Indeed this weakness in the market structure was noticed as early as 1997 in a CERA report on Californian electricity market deregulation in which it was pointed out that:

> "There is no reliable mechanism [in California] to pay for the fixed and operating costs of new generating facilities, … That is likely to lead to extended periods of low prices followed by periods of very high prices, as supply shortages and surpluses develop. Price volatility will not be conducive to a smooth transition to competition."

17. The structure of the market combined with the system supply shortages allowed generators to "play" the system and take advantage of, and artificially inflate, prices on the CalPX. By carrying out "maintenance" or choosing to export power out of California at times of peak demand generators were able to push prices on the CalPX even higher. A further flaw in the market relates to the relatively low numbers of players involved in both supplying and generating power. Insufficient incentives were provided to IPP's to build capacity and, as explained above, tight siting and environmental regulations also made it difficult to get capacity built in California. Equally, on the supply side, the state legislature in dismantling the monopoly system was very keen to protect consumers, particularly retail consumers, under the new market structure. As such extremely tight regulations were imposed on potential new Energy Service Providers (ESPs) which negated all the incentives designed to encourage new entrants into the market.

Supply – Demand

18. The fundamental problem that lay behind the energy crisis in California was the existence of an imbalance between supply and demand, an imbalance that was improperly handled and made worse by the actions and reactions of the authorities. Over the preceding decade the state failed to approve (and developers to build) adequate capacity to meet rising demand; between 1990 and 1999 electricity demand rose by 11.3% but supply capacity actually fell by 1.7% as some older power plants were retired. After 1990 no new major power plants were constructed, relatively few were planned and a significant number were shut down.

19. Incumbents and new entrants alike were unwilling to invest in capacity and transmission due to the uncertainty and difficulty of the regulatory situation. Furthermore, strict planning laws supported by a strong environmental lobby meant that it was extremely difficult to gain permission to build new capacity. On average, it took seven years to get a project from application to completion. This was in sharp contrast to

other states where power projects could be fast-tracked if deemed necessary by the regulator and local authorities.

20. California also faced the problem that it relied heavily on hydro generation for its electricity (much of it from outside the state). In an average year hydro accounts for more than 30% of supply. This was reduced to only 20% in 2000 as a result of poor rainfall. It must be noted that similar low rainfall in the summer of 2001 did not spark another crisis that year.

21. The supply side problem was exacerbated by California's reliance on imports of electricity from neighboring states particularly in the peak summer period. This was sustainable for many years because the region was generally oversupplied with generating capacity. Power surpluses in the southwest were caused by overbuilding of generation capacity in 1970s and 1980s which had been driven by demand forecasts which turned out to overoptimistic. Similarly, the Pacific Northwest (PNW), a major source of imports to California, had substantial supply available to export. Its supply is also ideal for California in that seasonal demand within the region is complementary with that of California; that is to say, peak demand in PNW is in winter whereas peak demand in California is in summer. However, surplus capacity built in both PNW and the southwest has been steadily absorbed by growing local demand thereby reducing that available for export to California. Clearly, California came to take out of state electricity for granted.

22. By the time of the crisis, the robustness of California's electricity supply system was compromised, peak reserve margins (i.e. the capacity available in reserve at peak periods) had fallen from a high of 18% in 1993 to around 5% in 1999 making the system dangerously vulnerable. It is clear, therefore, that the supply shortfall in California was fundamental to the energy crisis of 2000 and 2001 and was not a one off brought on by exceptional conditions but a result of a long running failure to invest or to encourage investment in sufficient new generating capacity both within and outside California. In addition there was a failure to build capacity close to the major centers of demand which in part was a result of the difficulty of gaining planning consent for power projects close to centers of population.

Gas Prices

23. The price of gas also played its part in exacerbating the effect of the California energy crisis. Close to 50% of California's instate generation capacity is driven by gas, such that the extremely high gas prices at the California border which were seen in November 2000 and February and March 2001 had a serious effect on electricity prices. At the same time the whole US was seeing a rise in gas prices with Henry Hub[2] floating around $10/MMBtu throughout late November, December and early January. These prices were small in comparison with the $50/MMBtu on the Californian border in November 2000 and the $30+ price seen in February and March 2001.

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[2] Henry Hub is the physical delivery location for gas traded under regulated futures contracts in the United States.

24. These high prices can be explained by a number of factors; the long running low gas prices in the US prior to the rises at the end of 2000 had meant a reduction in drilling activity over the preceding years which in turn led to the supply surplus being eroded. A further reason was the lack of an economic alternative fuel supply with the prices of competing fuels rising in parallel with gas. For power generators fuel switching was also not really an option with heavy environmental restrictions on burning fuel oil. In addition an explosion in August 2000 on one of the pipelines delivering southwestern gas to California meant reduced capacity at a time when supplies were already tight. The pipelines feeding into California have also been running at close to capacity, as have pipelines within the state. As such, stiff competition to gain access to capacity had an inflationary effect on prices. Furthermore, price spikes at the Californian border have also been blamed on suppliers withholding gas in order to take advantage of high prices and on “round-trip” trades conducted by Enron and others that intensified price spikes.

Developments since the Crisis

25. After the first quarter of 2001 the situation in California stabilised, the last brown or black outs being in March 2001. Similarly electricity spot prices fell back into line with long-term expectations. The explanation for this is manifold but there were several key reasons

i. FERC imposed temporary price caps to spot market price spikes
ii. Department of Water Resources signed long term power purchase contracts with generators (for above current electricity prices)
iii. Electricity consumption fell due to both more moderate temperatures in summer 2001 and major consumer conservation initiatives
iv. Fast tracking of new build generating capacity

26. By June 2001, natural gas prices in California fell back into line with Henry Hub and as drilling increased across the US and Canada it brought new supplies to market alleviating the supply shortages. Equally the constraints on infrastructure have been addressed, with the expansion of delivery capacity to California from 6630 MMcf/d in 2001 to 8310 MMcf/d in 2003, and additional expansion being considered. The CalPX has been disbanded and the state legislature has, through the Department of Water Resources, entered into a number of long term power purchase contracts with generators to ensure security of electricity supply to consumers within the state. The price cap imposed on spot electricity had the effect of curbing excessive prices for electricity within the state and helped to bring the situation under control. The weather intervened with temperatures that summer being moderate compared with 2000. In addition the state legislature also launched a major energy conservation program which included an energy efficiency rebate system which has had a significant effect on suppressing demand. Finally the state has radically overhauled the planning process for getting new generation capacity built, three major and six minor (under 150 MW) power plants , with a combined capacity of 1864.5 MW came on line in 2001. In 2002, a total on 2502.5 MW came on line, and in 2003, 3944 MW. In 2003, there was 4051 MW of generating capacity under construction, and 6007 MW under review.

Implications of the Crisis

27. The measures taken since the crisis brought the situation under control and many of the measures that have been taken will help prevent a recurrence of the crisis. New generating and gas pipeline infrastructure will address the long running supply shortfalls which were fundamentally behind the crisis. Equally the conservation program has also had a very positive effect. The cause of market liberalization has been damaged by the crisis but it is unlikely that there will be a return to the old monopoly based structures of the past; the uncertainty over the future will inevitably cause potential generators, suppliers and infrastructure developers to think twice before embarking on expensive projects. Similarly, one of the most important questions that has to be addressed is the way in which generating capacity and infrastructure are built in time to avoid the kind of supply shortfalls that lay at the heart of this crisis. Would a capacity market be able to read price signals in time to develop capacity as it is needed or do the lead times involved in building generation make this impractical?

28. It is essential to make the point that the Californian energy crisis does not represent a failure of market liberalization, but rather a failure to liberalize correctly. The market structure was fundamentally flawed and no one agency with enough authority had regulatory oversight for the development of the market as a whole. Since the crisis, measures have been taken to allow the Californian market to function effectively. CalPX stopped operating in January 2001. In February 2001 California's Department of Water Resources was permitted to purchase power under long-term contracts for sale to PG&E and SCE. In April 2001, FERC introduced a price mitigation plan for the spot market, and in May 2001, it was announced that prices would be raised by 19% for all except the most vulnerable customers. Also in May 2001, Senate Bill 28X was signed to shorten the time needed to review plans for building new capacity. It may well be that to produce an effective market more not less regulation is required and this is one of the key lessons that can be drawn from the crisis, liberalization does not mean deregulation, indeed the transition from a monopoly market to a free market requires heavy handed regulation to force the market open but that regulation needs to be focused and free from day-to-day interference from political bodies.

29. California’s electricity crisis remains an example of how not to organize energy markets. Ironically, it is not and was not a flawed gas market. The message to be learnt from it is not to avoid liberalization, but to ensure that new market reforms are structured on a practical basis, taking care to avoid the obvious mistakes of curtailed supply, total exposure to price risk and a multiplicity of regulatory bodies.

Romania

30. The Romanian gas liberalization development is highly relevant to Ukraine since the country faces similar problems of restructuring its economy to a market economy, it is a country with a highly developed gas industry with a long tradition of upstream industry and the liberalization of the gas industry is also highly politicized. Romania is one of the highest consumers and producers of energy in Central and Eastern Europe. By the early 1980s natural gas accounted for 55% of Romania’s total energy supply - the highest penetration any Central and Eastern European country has achieved. This

unusually large market share was due to former President Ceaucescu's policy of self-sufficiency at all costs, which led to short-term maximization of domestic gas production without heed to optimizing recoverability of reserves. The high inefficiency of the industry and falling gas production prompted the Romanian authorities to reform and liberalize the industry in order to reverse the negative development. Romania is in the process of reforming its energy industries but the reluctance of the government to introduce politically controversial and economically challenging reforms means Romania is moving slower than originally planned and progress in implementing key structural reforms and improving administrative capacity has been limited. Nevertheless, a number of changes have been implemented and liberalization is an objective.

31. The Romanian government has committed itself to increasing domestic production of oil and gas in order to reduce the country's reliance on imports. Restructuring of the gas industry has commenced with the "unbundling" of Romgaz into divisions for storage, production and transmission. A regulatory authority, the National Agency for Natural Gas Reserves, (ANRGN) has been created and continues to oversee the industry and introduce legislation, often with one eye on EU requirements with the intention of aiding Romania's accession process to the EU. Liberalization of the gas market has commenced with the creation of a free market to Eligible Customers, typically the largest gas consumers. However, Romania has been inconsistent in how it has applied the energy reform. A timeline of the main events in the Romanian legislation is shown below:

Table 3: Main events in Romanian legislation

1990	Passed first energy reform
1996	Introduction of the Petroleum Law
2000	ANRGN was established
2001	Romanian Energy Legislative was updated
2001	ANRGN re-opened the gas market
2002	New list of Eligible Customers

Source: Gas Strategies

32. As part of the Romanian energy reform passed in 1990, the sector was reorganized by separating policy and regulation from operation and function. On the production side, regional divisions were created to better manage output and supply, aided by commercial companies providing more centralized support. The intention was to break up the large, cumbersome companies inherited from the centrally planned economy of the Soviet era. In fact, little alteration was seen in practice as the inertia and, in some cases, hostility of existing bureaucracies proved resistant to change. As regards liberalization of the gas industry hardly any progress was made and the industry remained in the hands of the gas monopoly, Romgaz.

33. A second major change was introduced in the Petroleum Law passed in February 1996, which provided the legal framework for the operation of both Romanian and foreign companies. The law introduced third party access (TPA) to gas pipelines. The TPA was granted to other parties and the market was opened to a limited number of

largest industrial gas consumers. In 2000, Romania established a National Agency for Natural Gas Reserves (ANRGN). The Agency is responsible for issuing licenses, drafting operational legislation, establishing gas tariffs, and monitoring the observance of competition rules. All cross-subsidies have been reportedly removed in these sectors though in practice this is not easy to verify. The establishment of ANRGN as the national gas regulator is intended to be the main step towards creating a tool that, in the context of a free market, will: increase the security of supplying natural gas; facilitate free market transactions between licensed suppliers and eligible consumers; improve the dispatching and distribution system; optimize the delivery parameters for natural gas by specifying the precise quantities and pressures to be delivered by a direct contractual relationship between client and supplier. The Prime Minister appoints the president of ANRGN. The energy sector is under the supervision of the Ministry of Industries and Resources, which formulates policy and strategy.

34. However, the gas sector has been subject to considerable shifts in policy over the last three years. Whereas 15% of the market used to be open through licensed suppliers and eligible customers, the government suspended all bilateral contracts in October 2000 as winter supply shortages threatened domestic supplies. In July 2001 it re-opened 10% of the market to competition and the regulatory authority selected 18 new eligible customers, who were free to switch suppliers and operate in a “liberalized” market. In 2002 the regulator ANRGN selected 45 eligible customers with a minimum consumption of 5 MMcm in the previous year, with the intention of opening more than 25% of the national gas market to competitive pressure. As more eligible customers qualify for this status it is planned to have 33% of the market for gas in competition by 2006. Eligible customers are natural gas consumers that have the right to select their own supplier and to contract directly, having access to the transport/distribution network. They have the right to connect to and use the transport/distribution network. To qualify as an eligible customer the entity has to meet fairly strict criteria in different areas of activity. New eligible consumers have to re-apply for accreditation on an annual basis. Re-qualification as Eligible is not automatic. Eligibility commences on 31st January. The consumer loses the status of eligible customer if it does not fulfill its obligations under the contract concluded with the chosen supplier. In the event of contract breach the supplier can ask ANRGN for the suspension or cancellation of accreditation for the eligible customer. An independent producer can sell gas directly to an eligible customer if it is a licensed supplier.

35. Captive Customers are all customers that are not defined and qualified as eligible. One exception is Termoelectrica, the national electricity producer, (a de facto captive customer), a company that is not qualified as eligible but may be allowed to directly negotiate imported gas supply under contracts. As it is also the largest gas consumer in Romania, the reform of the electricity sector will undoubtedly affect the gas demand of Termoelectrica. As Termoelectrica restructures it may privatize a number of power plants, which may become Eligible Customers in their own right. The captive customers may only buy from the distribution companies at the ANRGN regulated price. Gas prices have been adjusted to reflect production costs and they are now indexed with the US dollar. The eligible customers may choose to buy either from distribution companies or

from licensed traders/suppliers. They can also buy from importers but only if the selling party holds a license to sell/distribute gas. There is a number of independent suppliers and importers who successfully supply gas directly to industrial customers. Romania has thus managed to open its gas market to large industrial consumers since it introduced non-discriminatory TPA. Apart from the Baltic republics, Romania is the only country in Central and Eastern Europe where liberalization has been successfully introduced. Although legislation was already introduced in 1990 the process only started once the transparent TPA was introduced in 1996. Nevertheless, there are some problems with the gas liberalization, because the complexity of the legislation and strict criteria mean that many industrial consumers are unaware that they could qualify, and thereby acquire access to the gas transit system and contract for new supplies. However, these are bureaucratic difficulties rather than real obstructions to the liberalization.

Germany

36. The liberalization process in Germany is largely driven by EU directives. Germany has been one of the slowest to adopt the EU directive, and it only became law in 11 April 2003, when the federal government passed the amendment to the 1998 German Energy Law. Germany is virtually alone in attempting to implement the EU third party access agreement by means of a negotiated rather than a regulated mechanism. The system of negotiated TPA to pipelines as it has developed in Germany since 1998 is based on private, voluntary industry agreements, the so-called Verbandevereinbarungen. These agreements set common pricing guidelines for industry participants, but are negotiated on a case-by-case basis by the parties involved.

37. The chronology of liberalization process in Germany is outlined below:

Table 4: Chronology of the German Gas Market Liberalisation Process

1998	April - German Energy Law passed, June - EU Directive passed
2000	July - German VVI for gas agreed
2001	March – First amendment to VVI for gas agreed
2002	March – at Barcelona summit Germany succeeds opt out from EU requirement to set up regulator, May – German VVII for gas signed
2003	February – EU amendments to original energy directive passed, April – industry talks on German VVIII for gas break down, German government passes amendment to Energy Law, September – German gas code VVII expires
2004	Q1 – German government to finalise regulatory framework, July – German regulatory framework comes into force

Source: Gas Strategies

38. At present Germany still has no independent regulator. Instead it has a system of self-regulation based on voluntary agreements between industry participants. Germany's Federal Cartel Office (FCO) carries out the supervision on an ex-post basis, which is a government-funded but independent entity responsible for ensuring that German business

adheres to national and EU competition law. FCO has the power to investigate network access charges when it has grounds for suspecting that prices are excessive, both in response to customers' complaints and on its own initiative. It has the power to reduce the price. However, German transmission and storage charges are well above the relevant EU average. Although the EU's legal requirement that all member states establish an energy regulator by July 1, 2004 is that it still leaves a lot of discretion to the governments of each member state in deciding on the nature and scope of the regulatory framework.

39. The German gas industry is concentrated at the transmission level but extremely fragmented at the distribution level. The distribution level is very politicized because it is dominated by municipal-utility companies that generate much needed finances to the municipal authorities, which are currently experiencing severe budgetary difficulties. The financing of municipalities is a major concern to the federal government and thus government decision on the regulator will be influenced by this factor.

40. German gas market is currently theoretically free and 100% open to competition but this is only theory. In practice change has been limited and very slow. However, court cases under domestic and European competition law have opened up volumes under old long-term contracts to competition. But little has changed at the customer end because Germany has opted for negotiated third-party access, which has not so far brought down network charges sufficiently for competitors to make real inroads into the market. Storage is still a particularly difficult area. The vagueness of the EU Gas Directive originally gave incumbents hope that, although they had been obliged to concede the principal of third party access to pipes, they might be able to eviscerate the overall impact of that measure by denying access to storage. In Germany access to storage is particularly important for new suppliers looking to use Interconnector gas because the Interconnector is a sub-sea pipeline, which closes for maintenance for about two weeks per year (and has recently suffered unplanned downtime as a result of liquid incursion). Therefore without storage somewhere it cannot be a source of firm gas. Without storage facilities in Germany, close to customers, a supplier has no hope of offering seasonally structured gas on competitive terms.

41. In July 2003 the German gas industry group, the BGW, published a survey of 700 grid operators, as well as TPA contracts which had been agreed since July 2000 when the Verbändevereinbarung Gas agreement became effective. Around 469 TPA contracts had been made since July 2000, with approximately 180 of these agreements being signed between the beginning of the current gas year and April 2003. The survey indicated that, since July 2000, there had been a tripling of the cumulated gas volumes, reaching a total of around 77.5 billion kWh in April, which had been transported via TPA contracts. However, the consumer lobby group, VIK, was critical of the methodology used by the BGW. The group suggested that the number of TPA contracts was small in relation to the 700 active grid operators, but more significantly, the number of contracts was unimpressive when compared to the number of transportation cases underlying the TPA contracts, which had not been included in the BGW statistics. The VIK explained that if a gas supplier transports gas across Germany, the supplier may require several TPA

contracts in order to ship the gas through various grid systems. The BGW had, for the purposes of the survey, simply added up all contracts which represented a distortion of actual competition. On the grid operator's side, a large number of contracts have involved major gas distributors.

42. The EU Directives impose obligations on Germany in two specific areas: one is legal unbundling which is to be introduced to prevent cross-subsidization among company divisions; and the other is stricter ex-ante regulation in relation to conditions for network access and fees for network use. The structure of the German gas market, with several providers across the municipalities, may yet prove to be a favorable landscape for the emergence of competition. The lack of transparency of TPA and regulatory framework resulted in the slow process of gas liberalization in Germany. As regards gas liberalization within the EU Germany has become the laggard among the member's countries. As a result no customer group in Germany has enjoyed falling end-user prices since the process of liberalization started. Other EU members on the other hand have achieved falling end-user prices over the same period despite the rise in gas border price since 2000. Moreover, not only are German prices high compared to the EU average; they have actually risen for small commercial customers and for households.